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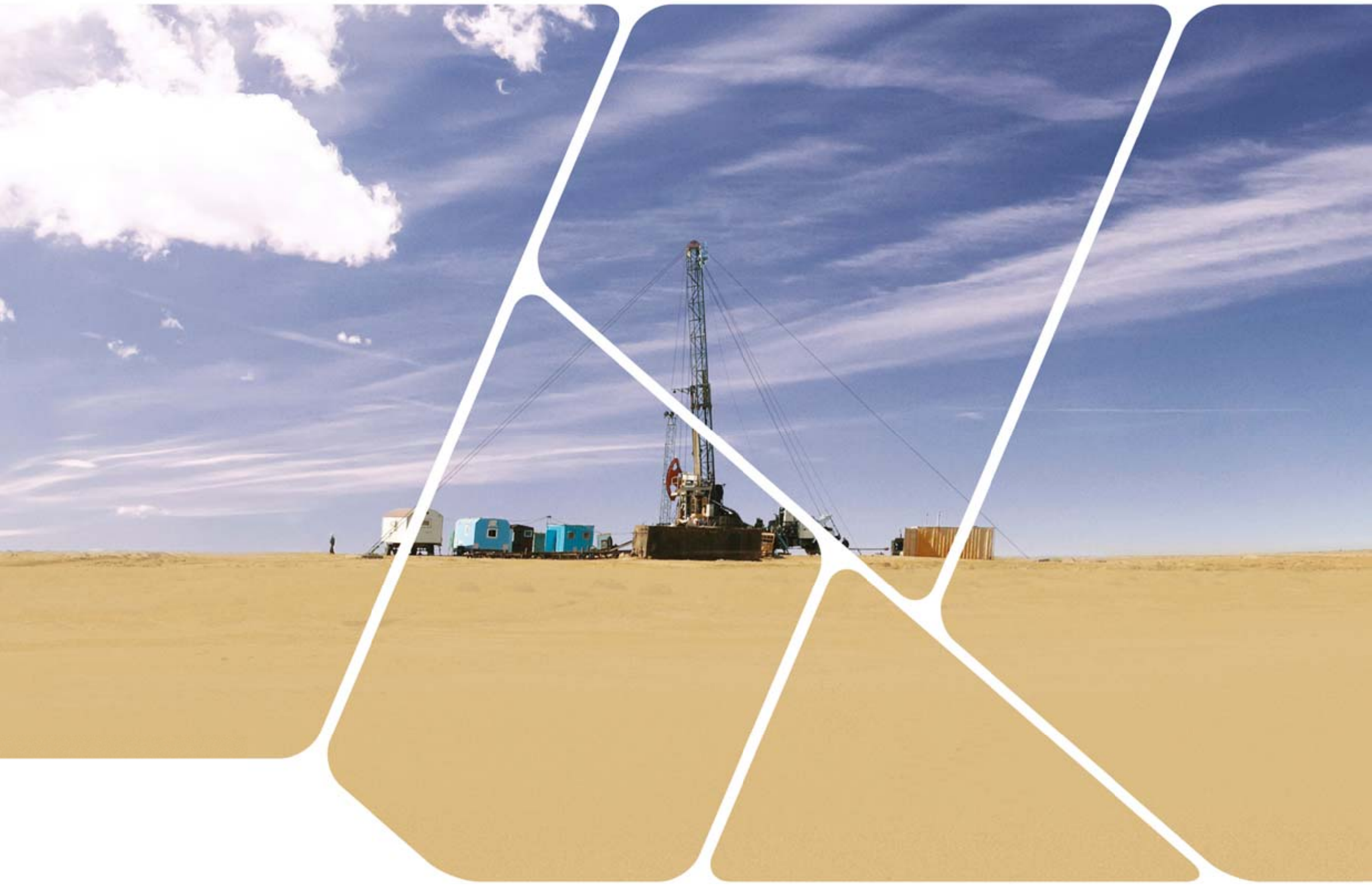

RESERVOIR ENGINEERING GRADUATE CERTIFICATE - *Week 8*

Drive Mechanisms -EOR

A special course by IFP Training for REPSOL ALGERIA
Alger –December 18 to 22, 2016

REPSOL

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Course contents

An IFP Training Course for REPSOL

Material balance MBAL™ *software*

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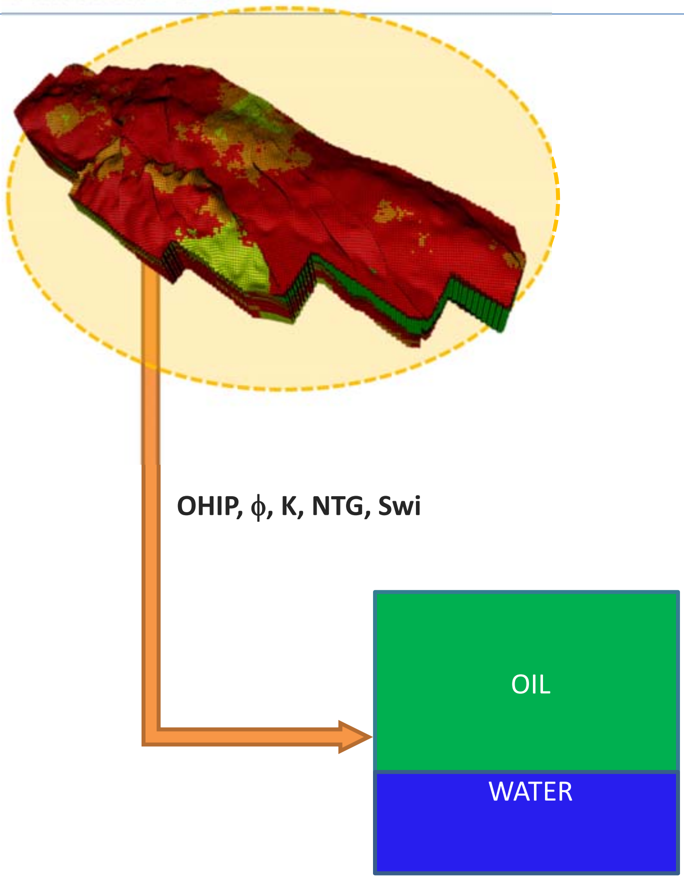
Contents

1. The tank model

Tank model



THE RESERVOIR IS REPRESENTED BY A TANK WITH
A UNIQUE POROSITY, PRESSURE, SATURATION

- Very simple model
- Material balance equation
- Checking data consistency
- Determines the fluids in place
- Estimates the aquifer type and size
- Production prediction

Tank model

- The model is set up by entering the fluid properties (ρ, μ, FVF and the reservoir parameters (geometry, ϕ, K, Swi). The calculations considers viscous and gravity forces.

- The Buckley-Leveret technique is used to calculate the movement of a flood front along a 1D reservoir section. Water displacing oil from downdip and gas displaying oil from the updip direction can be modeled.

- From PVT and reservoir properties, fractional flow can be calculated for either gas or water displacing oil. The effect of dip angle, injection rates and relative permeability can be evaluated.

Tank model

- The material balance is suggested as a necessary step prior to carrying out a simulation study.

- The material balance will always enable the drive mechanisms to be identified.

- A material balance study can provide OHIP and drive mechanisms as inputs to the simulation.

2. Material balance calculation

Symbols used in material balance equations

Bg	Formation volume factor for gas (res.vol./st.vol.)
Bo	Formation volume factor for oil (res.vol./st.vol.)
Bw	Formation volume factor for water (res.vol./st.vol.)
Cr, Cp	Pore compressibility (pressure-1)
Cw	Water compressibility (pressure-1)
ΔP	P2-P1
Ef,w	Rock and water expansion/compression term
Eg	Gas cap expansion term
Eo	Oil & solution gas expansion term
G	Original gas in place (st.vol.)
Gi	Cumulative gas injected (st.vol.)
Gp	Cumulative gas produced (st.vol.)
m	Initial gas cap size (res.vol. of gas cap)/(res.vol. of oil zone)
N	Original oil in place (st.vol.)
Np	Cumulative oil produced (st.vol.)
P	Pressure
Pb	Bubble point Pressure
Rp	Cumulative producing gas-oil ratio (st.vol./st.vol.) = Gp/Np
Rs	Solution gas-oil ratio (st.vol. gas/st.vol. oil)
Sg	Gas saturation
So	Oil saturation
Sw	Water saturation
T	Temperature
Vb	Bulk volume (res.vol.)
Vp	Pore volume (res.vol.)
We	Cumulative aquifer influx (st.vol.)
Wi	Cumulative water injected (st.vol.)
Wp	Cumulative water produced (st.vol.)
ρ	Density (mass/vol.)
ϕ	Porosity

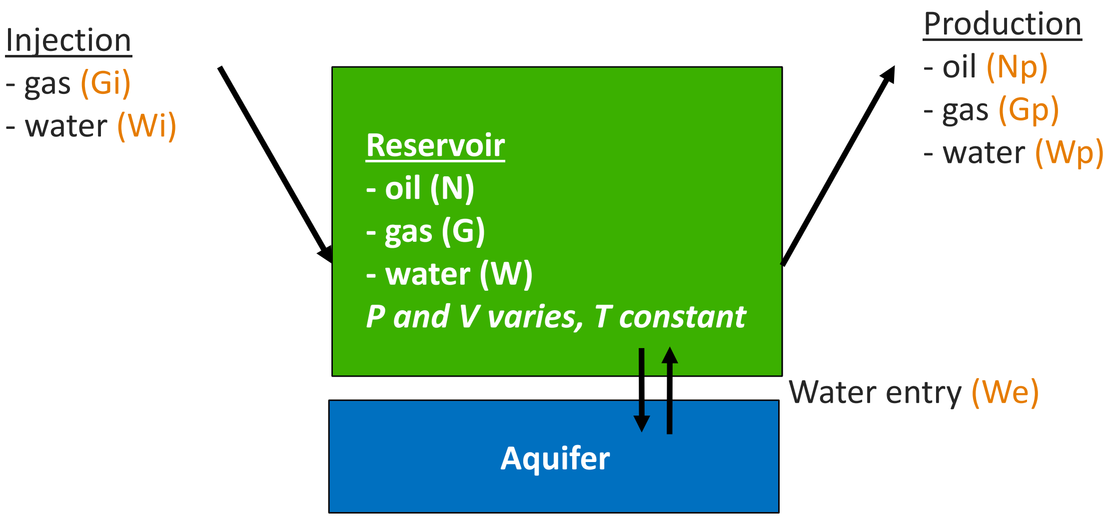
Different recovery mechanisms...

- **Natural drainage mechanisms (primary recovery)**
  - Rock & fluid expansion
  - Solution gas drive
  - Initial gas cap expansion
  - Aquifer water influx
  - Combination drive
  - Gravity drainage

- **Secondary recovery**
  - Water injection
  - Immiscible gas injection

Remember... Principles of material balance calculation

- **In material balance calculation, the reservoir can be seen as a black box (no heterogeneities), whose pore volume varies (pore shrinkage), where fluids go in and out, and whose pressure varies accordingly**



N, G, W, Np, Gp, Wp, Gi, Wi are volumes, expressed in standard conditions

Natural drive mechanism of an opened reservoir

- **Let us take the general case of a reservoir with an oil rim overlain by a gas cap and underlain by an aquifer**
- **The oil rim is produced and the production at the surface will consist of oil, gas and water**
- **The volumetric material balance expressed at reservoir conditions is:**

Initial volume occupied by the oil =

oil volume left in the reservoir with its dissolved gas

+ liberated gas from oil and staying in the reservoir

+ gas volume from the initial gas cap invading the oil zone

+ water entry

– produced water

Generalized material balance

- **The material balance equation becomes:**

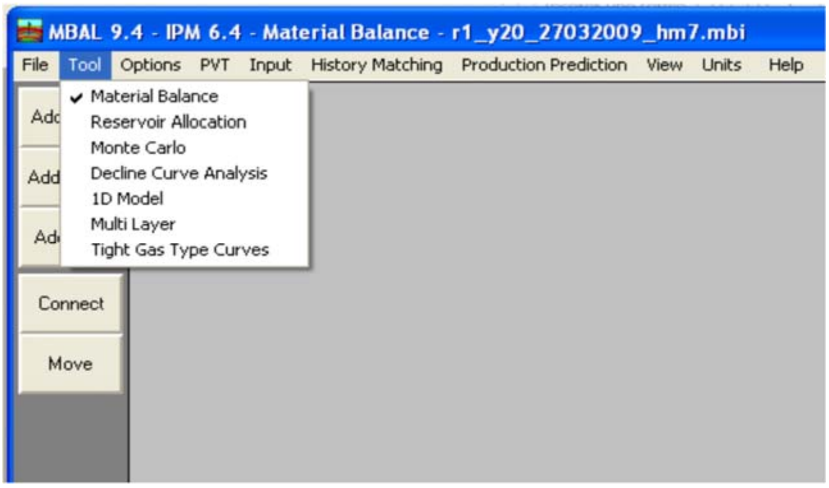
$$N.Bo_i = (N - Np)Bo + [(N.Rs_i - Gp) - (N - Np)Rs]Bg$$
$$+m.N.Bo_i\left(\frac{Bg}{Bg_i} - 1\right) + We - Wp.Bw$$

- **Introducing *Rp* definition:** $Rp = \dfrac{Gp}{Np}$

$$Np[Bo + (Rp - Rs)Bg] = N[(Bo - Bo_i) + (Rs_i - Rs)Bg]$$
$$+m.N.Bo_i\left(\frac{Bg}{Bg_i} - 1\right) + We - Wp.Bw$$

3. The MBAL software

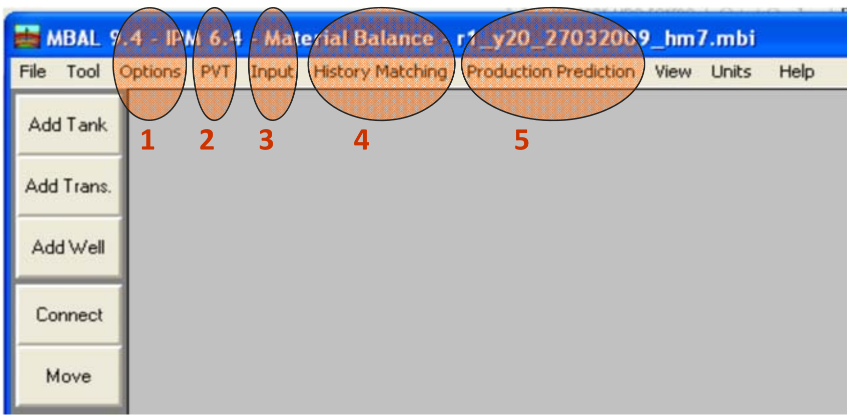
MBAL tools



- **Material Balance**
  - Production data matching
  - Production forecast
- **Reservoir Allocation**
- **Monte Carlo volumetrics**
- **Decline curve Analysis**
- **1-D model (Buckley Leverett)**
- **Multi Layer (relative permeability averaging)**
- **Tight Gas Type Curves**

Start using MBAL

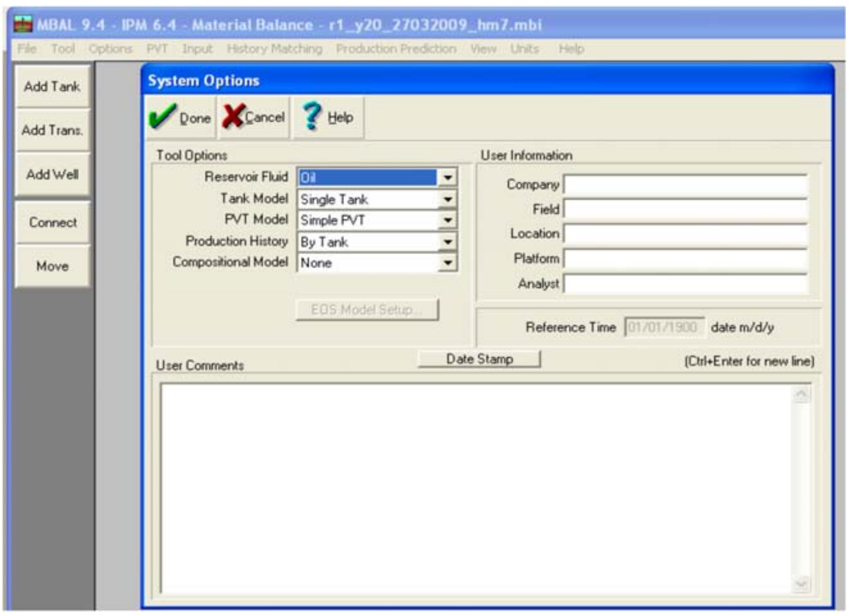
- **Applications: Identify/confirm production mechanisms**
  - Checking data consistency (OOIP, OGIP, Aquifer)
  - Production prediction
  - Sensitivities to different parameters
- **5 main modules:**
  1. Options
  2. PVT
  3. Input
     - Well data
     - Tank data
     - Transmissibility data
  4. History matching
  5. Production prediction



Options

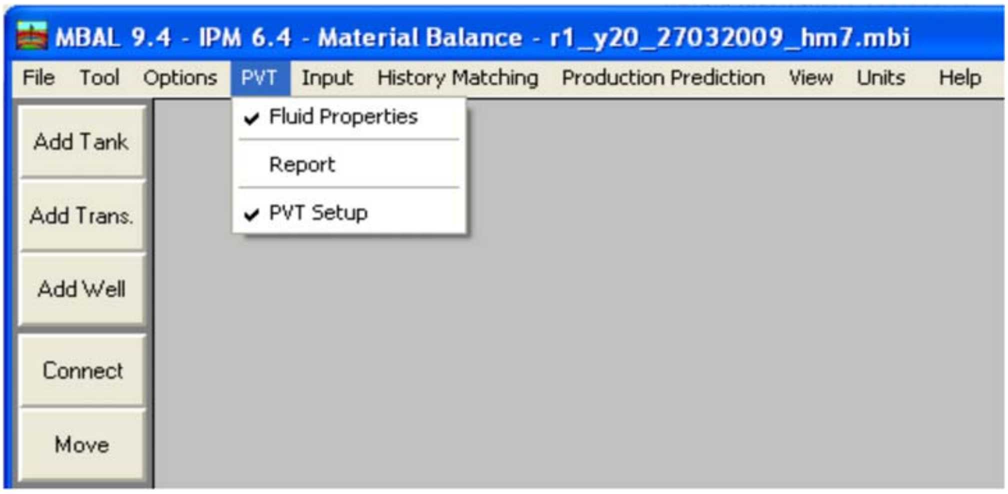
Definition of the model:

- Reservoir fluid:
  - Oil
  - Gas
  - Ret. Condensate
  - General
- Tank model:
  - Single Tank
  - Multiple Tanks
- PVT model:
  - Single PVT
  - Variable PVT
- Production history:
  - By Tank
  - By Well
- Compositional model:
  - None
  - Tracking
  - Fully Compositional



PVT

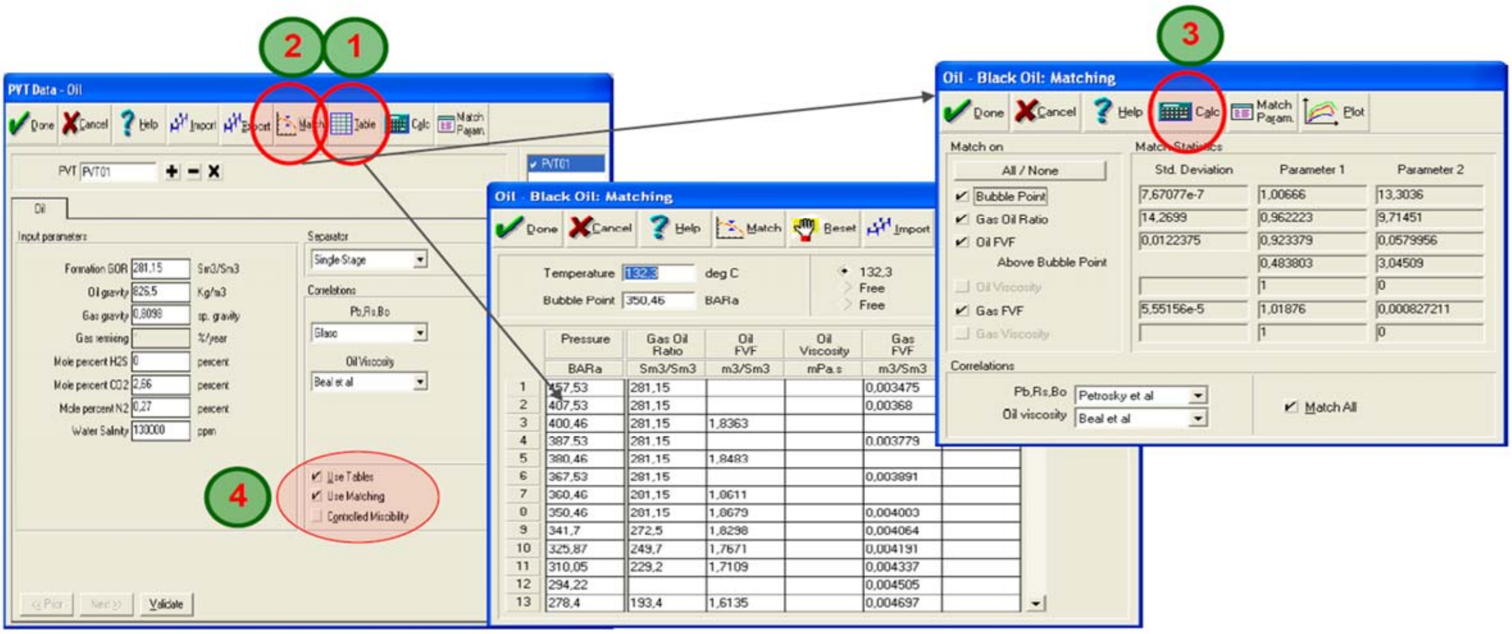
- **Applications:**
  - bring productions back to reservoir conditions



PVT - possibilities

- **Using “raw" correlations (1)**
  - if few laboratory data (prospect)
- **Using PVT tables data from PVT laboratory (2)**
  - if PVT tables are coherent & complete
- **Using matched correlations (3)**
  - if PVT tables are not complete
- **Using lab data & correlations (4)**
  - MBAL uses tables inside the pressure range & correlations outside → Recommended

PVT: use tables + matching options (4)



MBAL – PVT quality

The quality of the Mbal model depends on the PVT quality

→use complete black oil tables (Bo, Rs, µo, Bg) from PVT package calculator with a wide range of Pressure & Temperature

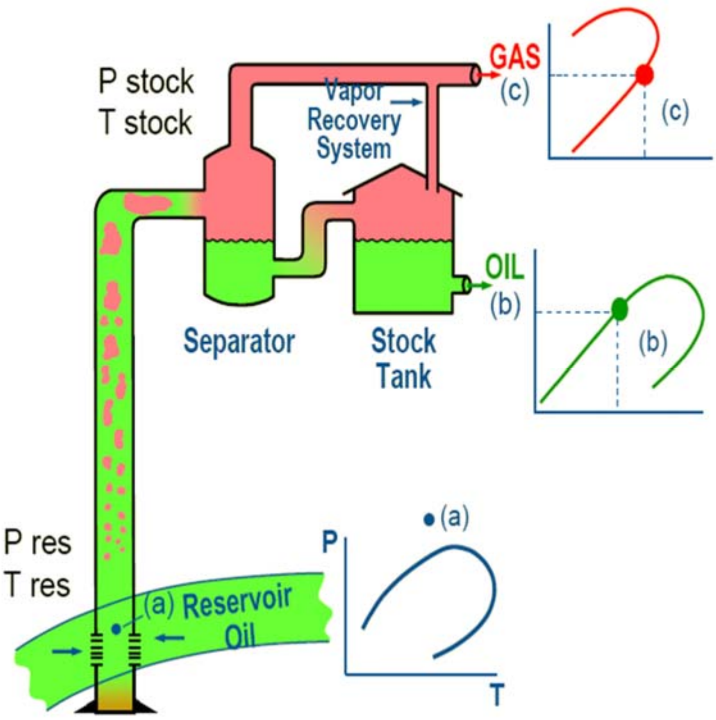
- **For oil**
  - a composite PVT is necessary for oil
- **For condensate gas**
  - a CCE (Constant Composition Expansion) simulation is needed as input in MBAL
  - a check of the liquid drop out deposit in the reservoir is imperative.
- **For dry or wet gas**
  - a composite PVT is necessary as input in MBAL

The MBAL software

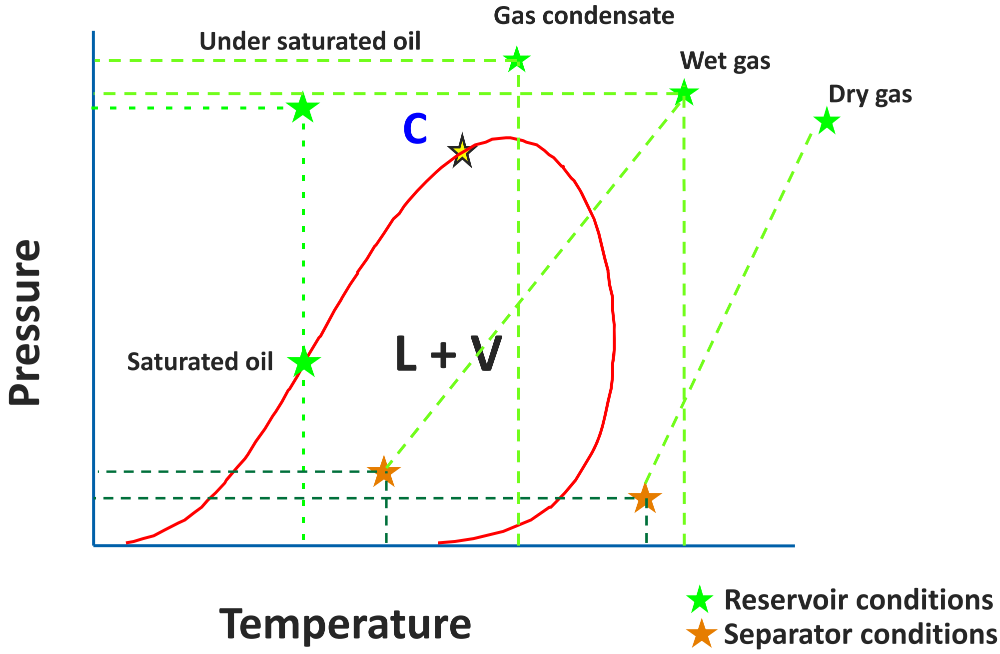
- PVT reminders

Fluid description

At reservoir conditions, the fluid is outside the phase envelop, fluids have different classifications depending on the position respect to the critical point. When reservoir fluids are produced, conditions change and we pass the bubble point or the dew point line (except for the dry gas) and we will have two phases at surface conditions.



Petroleum fluid classification



BLACK OIL MODEL: small variations of composition

COMPOSITIONAL MODEL: recommended near the critical point

Reservoir fluid representation - Composite PVT

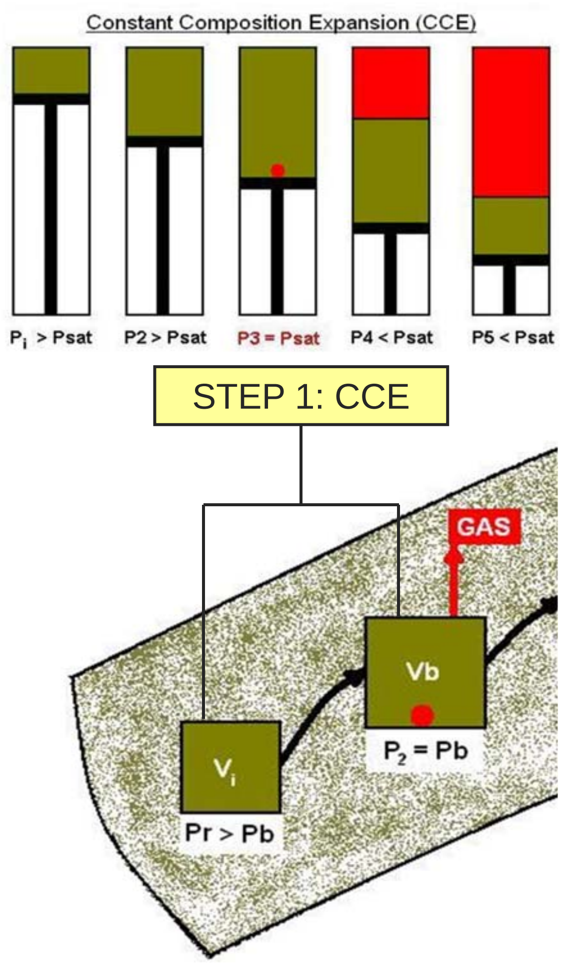
- **A fluid sample will follow a composite path between its original location in the reservoir and its final destination at the surface**

- **First step**
  - Fluid moves in the reservoir above saturation pressure
  - Volume change versus pressure is identical to CCE

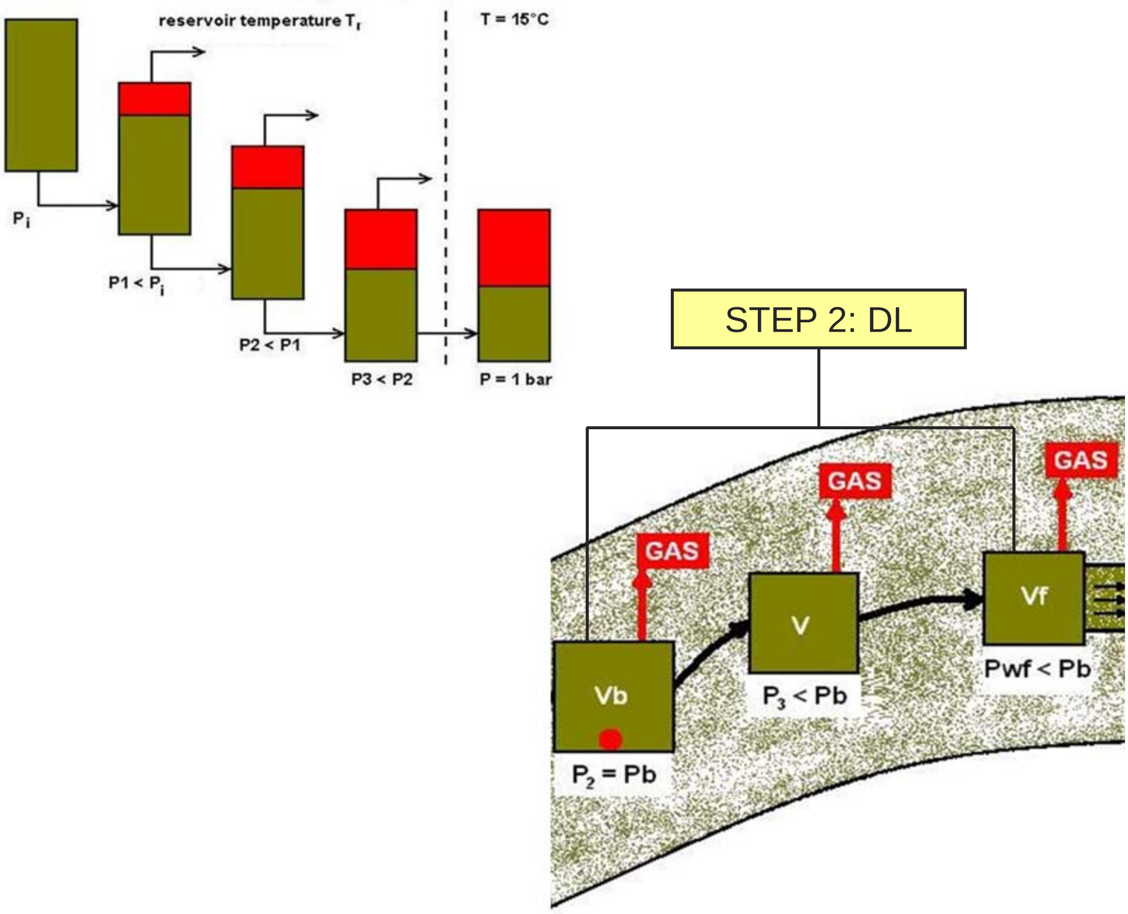
- **Second step**
  - Fluid moves in the reservoir below saturation pressure
  - Liquid composition versus pressure is identical to a CVD

- **Third step**
  - Fluid has reached the well bore
  - Volume and composition surfaces are identical to a flash process

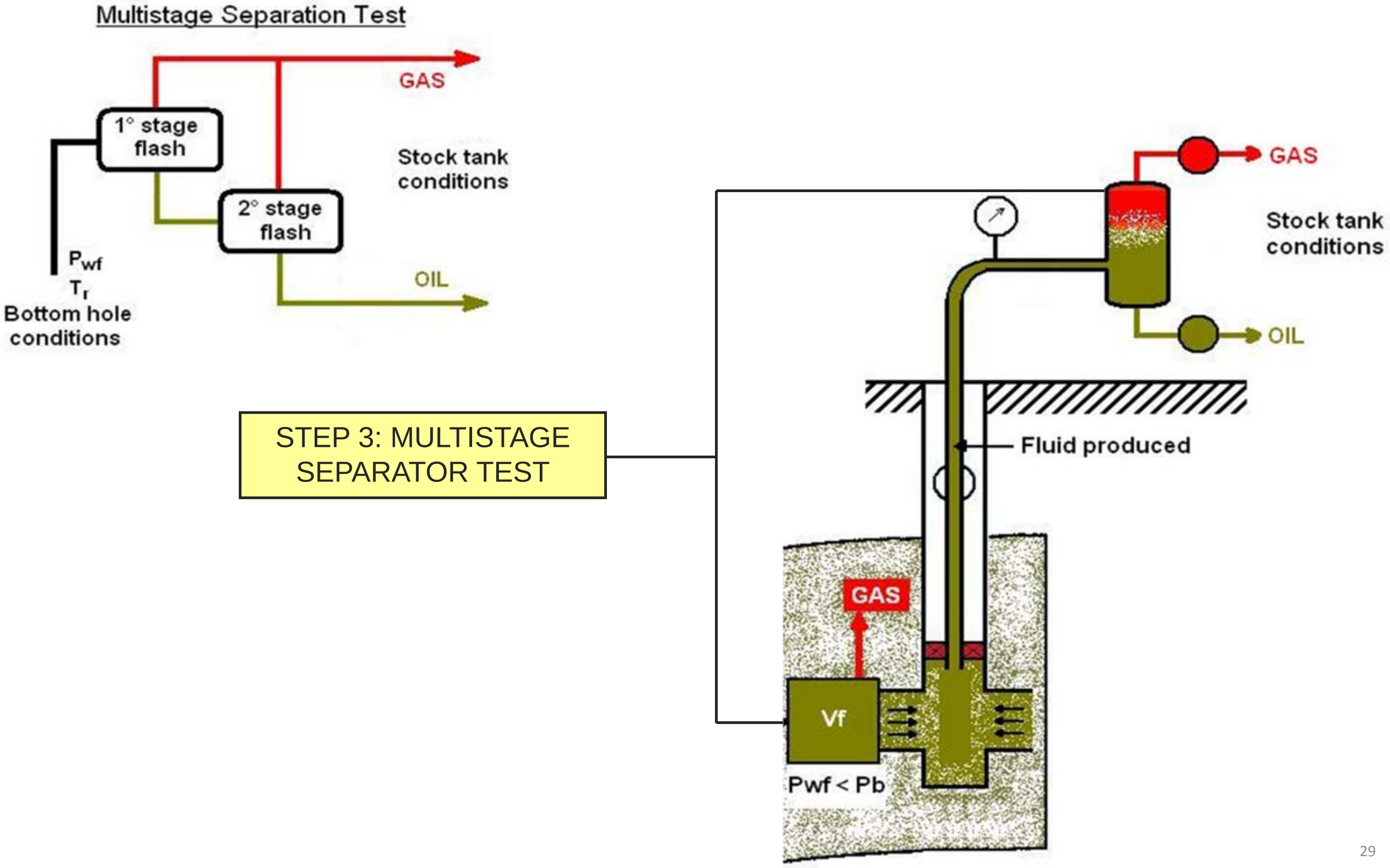
Reservoir fluid representation - Composite PVT



Reservoir fluid representation - Composite PVT

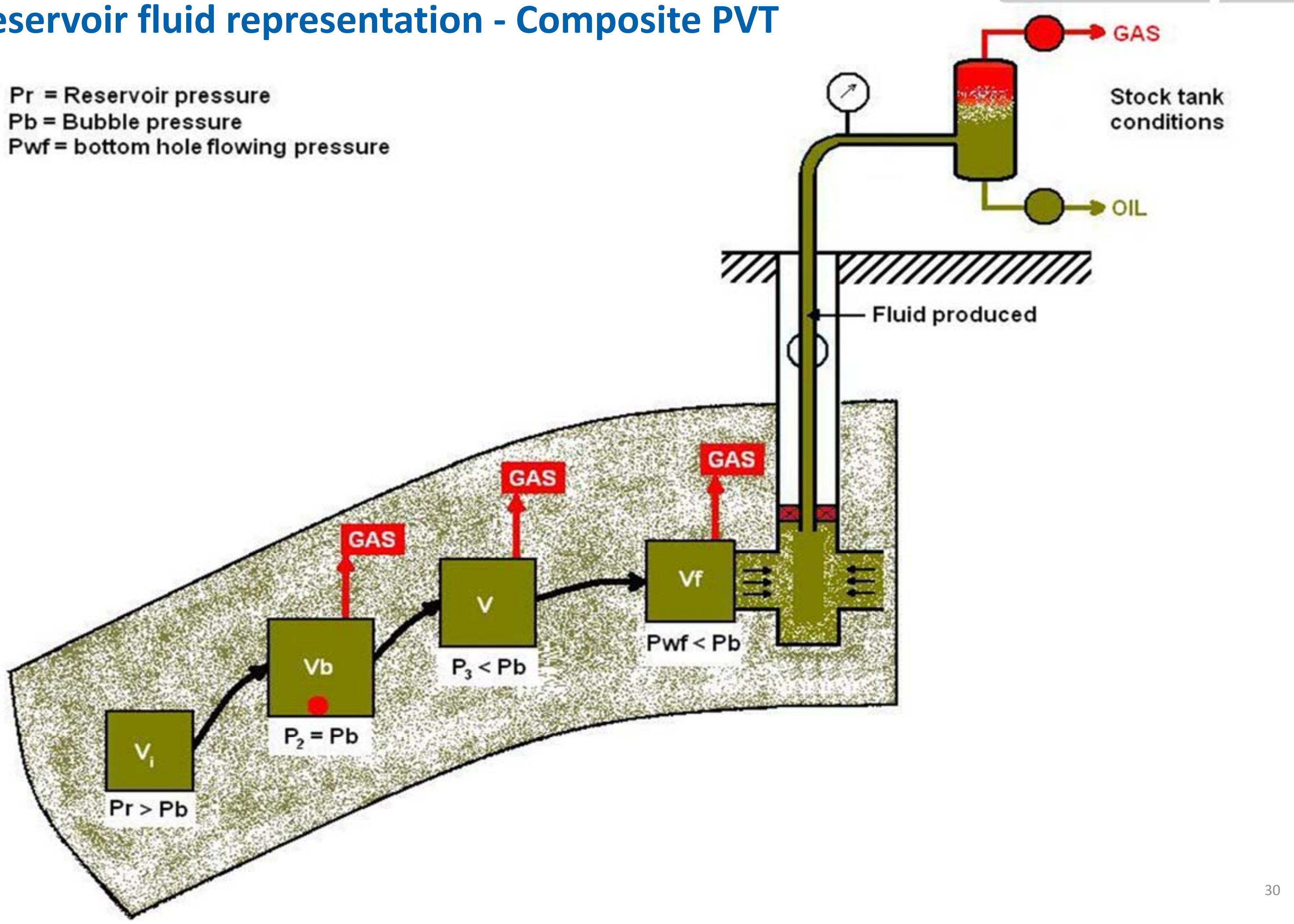


Reservoir fluid representation - Composite PVT



Reservoir fluid representation - Composite PVT

Pr = Reservoir pressure
Pb = Bubble pressure
Pwf = bottom hole flowing pressure



...Which PVT to choose?

- **A fluid sample will follow a composite path between its original location in the reservoir and its final destination at the surface**

- **First step**
  - Fluid moves in the reservoir above saturation pressure
  - Volume change versus pressure is identical to CCE

- **Second step**
  - Fluid moves in the reservoir below saturation pressure
  - Liquid composition versus pressure is identical to a CVD

- **Third step**
  - Fluid has reached the well bore
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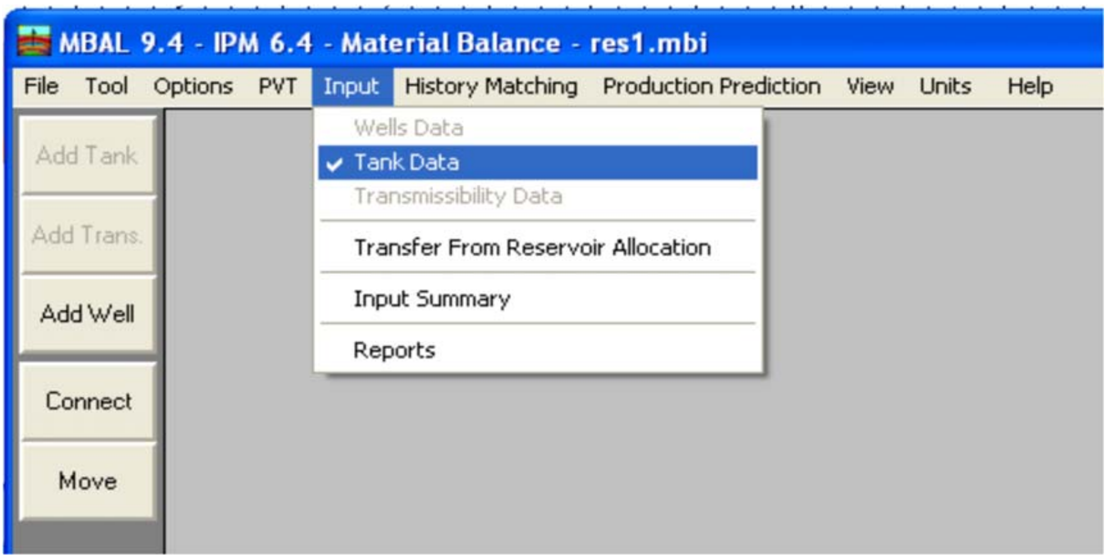
Notes

The MBAL software

- Tank input data

Input

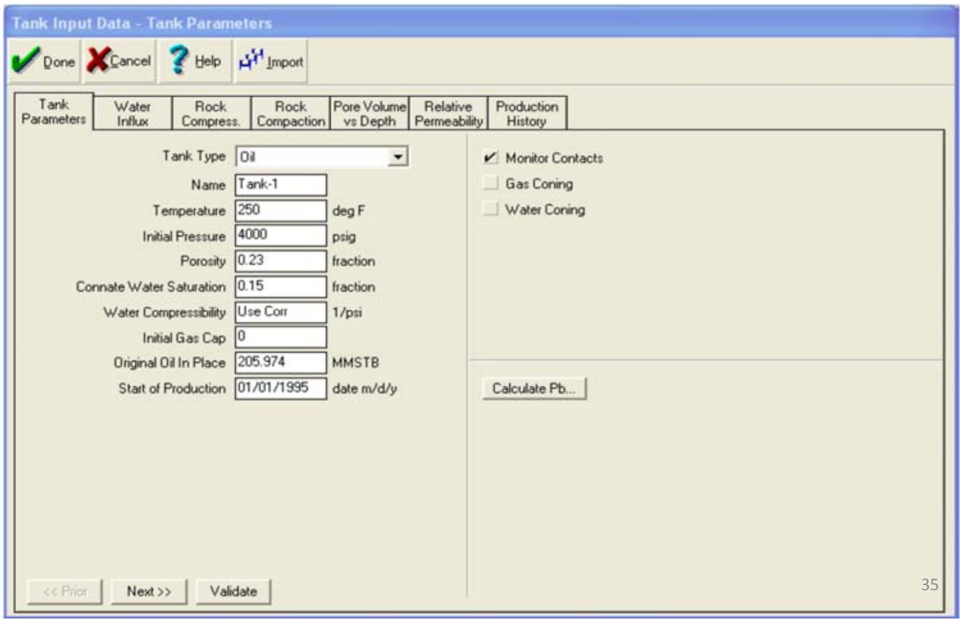


- **Applications:**
  - Define well parameters
    - (if production history « by well » was selected in the Option module)
  - Define tank parameters
  - Define transmissibility parameters
    - (if multiple tanks was selected in the option module)

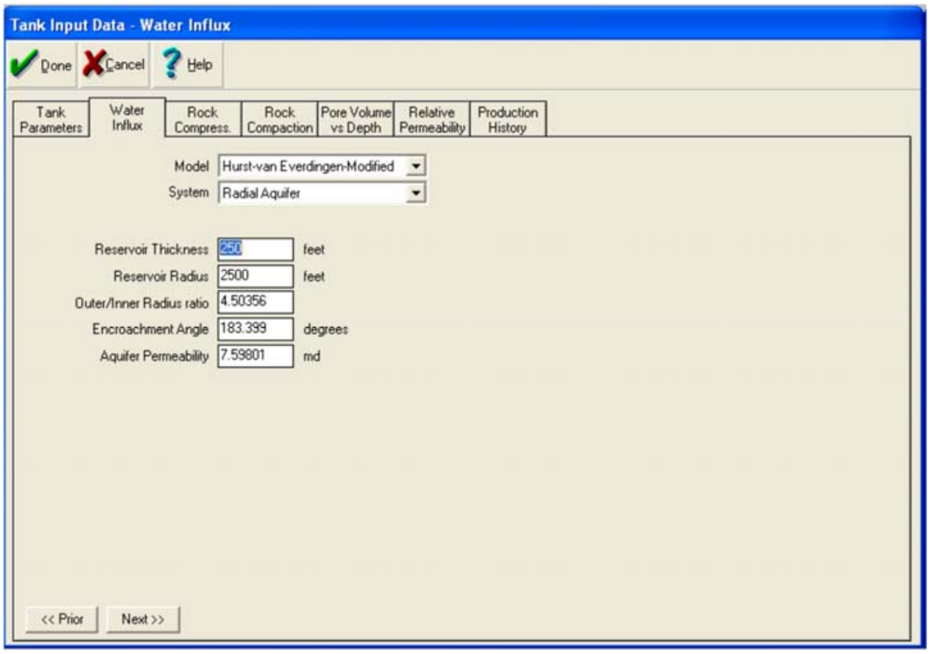
Input/Tank data – reservoir parameters

▶Tank/Reservoir characteristics:

- Tank type (Oil, water,...)
- Name
- Temperature
- Initial pressure
- Porosity
- Swc (connate water saturation)
- Water compressibility
- OOIP, OWIP
- Initial Gas cap via m
- Start of production



Input/Tank data – water influx



▶ Aquifer characteristics:

- Aquifer type
- Aquifer system (radial, linear, bottom,...)
- Aquifer geometric parameters

The MBAL software

- Aquifer models: reminders

Water drive

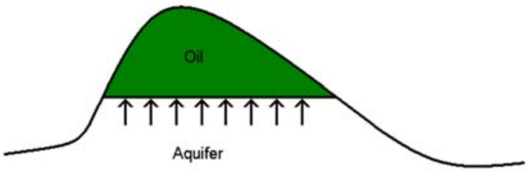
General principles

- The primary source of energy is provided by the water influx into the reservoir, which results in pressure maintenance
- In most cases, the energy comes from aquifer compressibility: Ca = Cp + Cw
- Water drive effectiveness is a function of the aquifer connection in the short term and the aquifer volume in long term

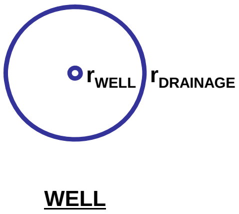
Water drive

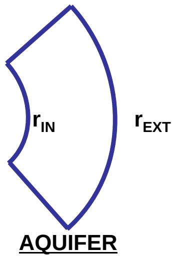
Aquifer configuration

- **The bottom water drive aquifer: it is in contact with the entire hydrocarbon area. The water invasion occurring vertically is governed by the reservoir vertical permeability.**



- **The edge water drive aquifer: the water entries take place laterally. Horizontal permeability is governing the water movement.**





Natural water influx

Material balance

- **Assuming P_b << P (for simplicity)**
  a. Oil volume expands
  b. Water volume expands
  c. Pore volume decreases
  d. Aquifer expands => Water entry W_e
  e. Water production W_p
- **Oil production = a + b + c + d – e**

$$Np.Bo = N.Bo_i.Ce(Pi - P) + We - Wp.Bw$$

$$RF = \frac{Np}{N} = \frac{Bo_i}{Bo}Ce(Pi - P) + \frac{We}{N.Bo}$$

- **The water entry depends on the aquifer model, considering an instantaneous expansion:**

$$We = Ca.Vw.(Pi - P)$$

$$Ca = Cw + Cp$$

Water entry calculation

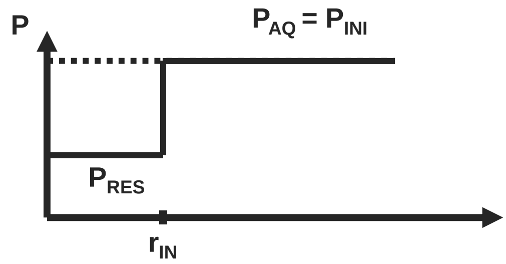
Aquifer models

1. **Small pot: Independent time equation** $We = Ca.Vw.(Pi - P)$

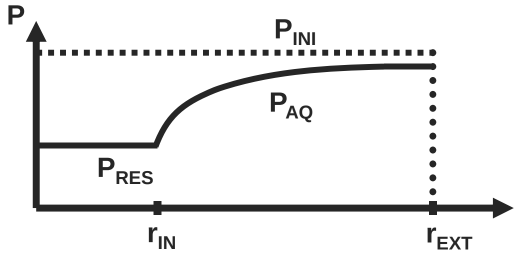
2. **Pseudo steady state: Fetkovich**

$$\Delta We = J.(Pi - P).\Delta t$$

J is the Fetkovich productivity index



3. **Transient: Carter Tracy model, approximate solution to diffusivity equation**



Notes

The MBAL software

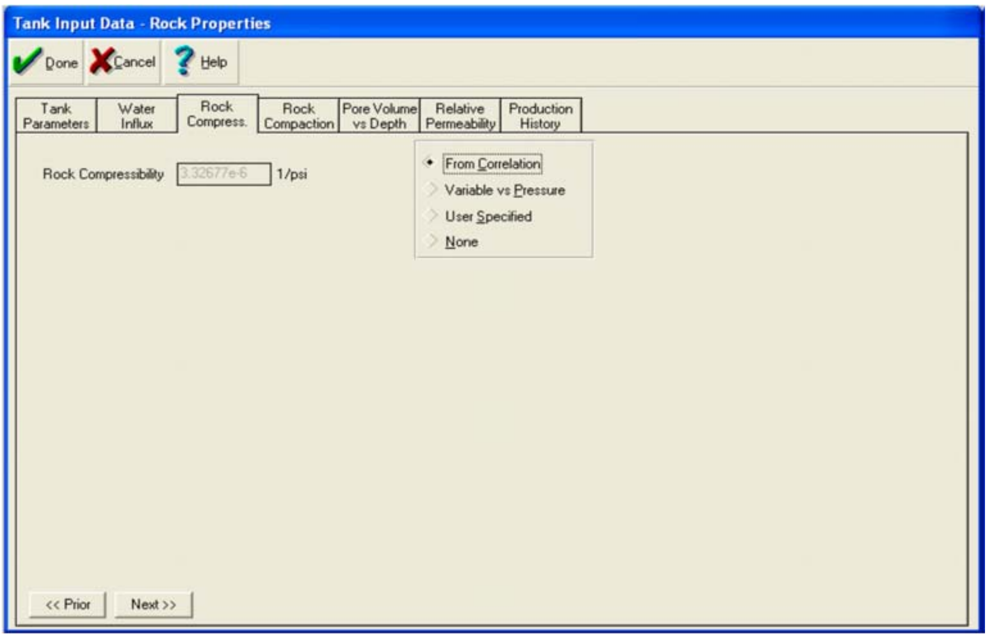
- Tank input data

Input/Tank data – rock compressibility

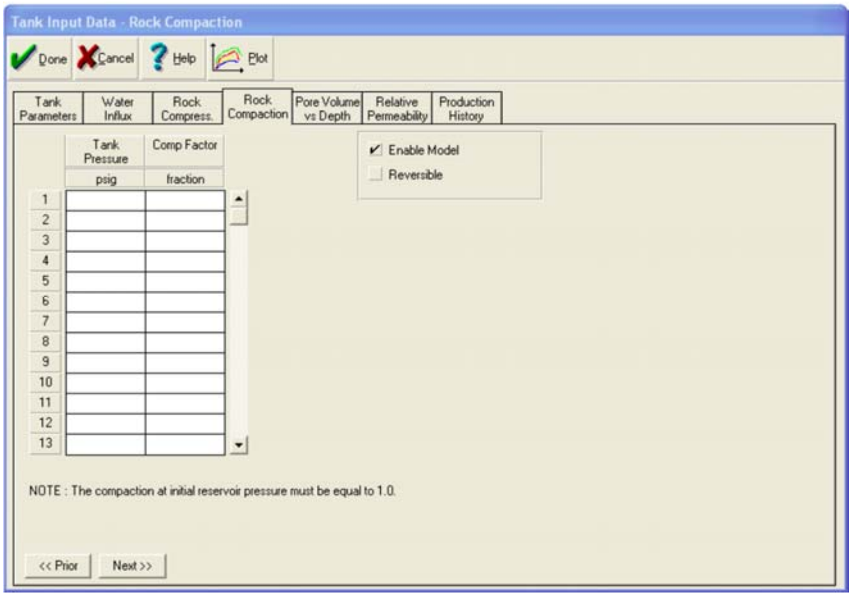
▶ **Rock compressibility characteristics:**

$$C_f = -\frac{1}{V}\frac{dV}{dP} \cong -\frac{1}{V_i}\frac{V - V_i}{P - P_i}$$

- Use of internal correlation
  - If the porosity of tank $\Phi > 0.3$ then $Cf=3.2e^{-6}$
  - If the porosity of tank $\Phi < 0.3$ then $Cf=3.2e^{-6}+(0.3-\Phi)^{2.415}*7.8e^{-5}$
- Variable vs. Pressure:
- User specified
- None



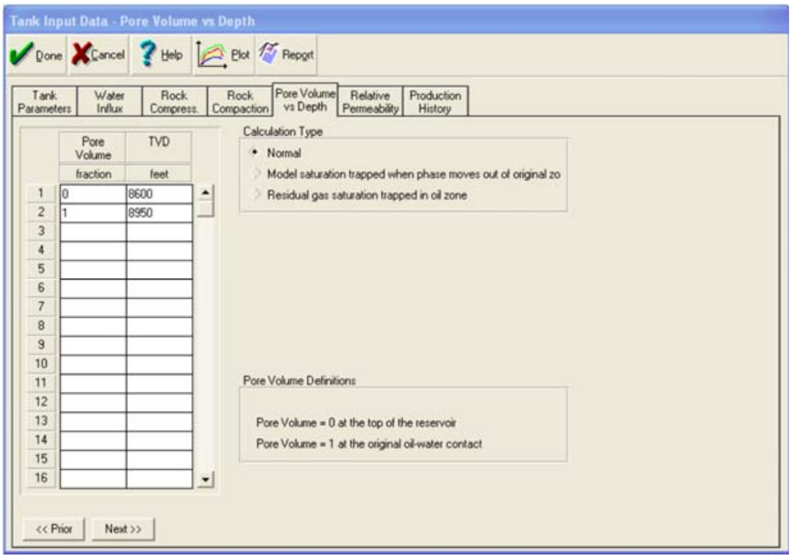
Input/Tank data – rock compaction



- **Rock compaction characteristics:**
  - Define a compaction factor of the pore volume vs. tank pressure
    - PV = PVi x compaction factor(P)
  - Define a reversible compaction factor of the pore volume vs. tank pressure
    - To have a PV increase if the reservoir re-pressurizes

Be careful if you use a rock compaction model & a rock compressibility model then MBAL will calculate a PV by using: PV = PVi x (1-Cf(Pi-P)) x compaction factor(P)

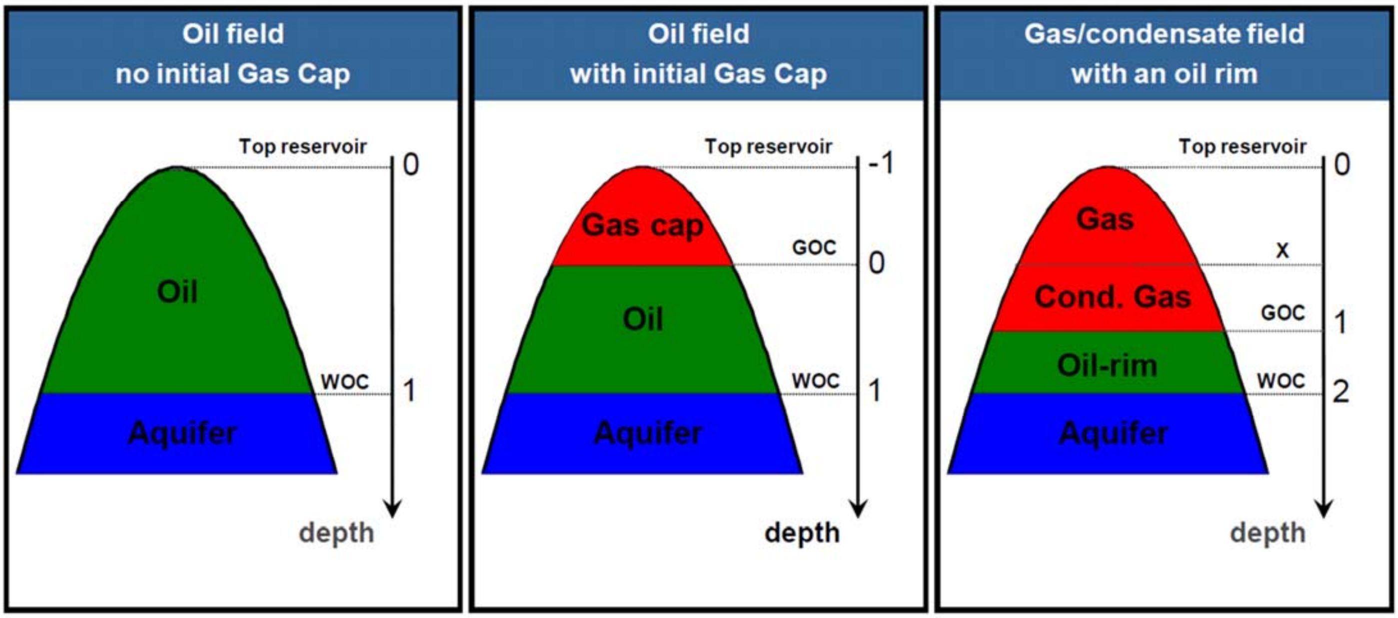
Input/Tank data – pore volume vs. depth



- **Pore volume vs. depth characteristics:**
  - Define a normal pore volume vs. depth law
  - Define a saturation trapped when a phase moves out of the original zone:
    - When a phase invades the pore volume originally occupied by another phase, then a given saturation can be set as trapped
  - Define a residual gas saturation trapped in oil zone
    - The gas will remain in the oil pore volume until the critical gas saturation is reached
- **Necessary if the option 'Monitor contact' is switched 'on' ('tank parameters')**

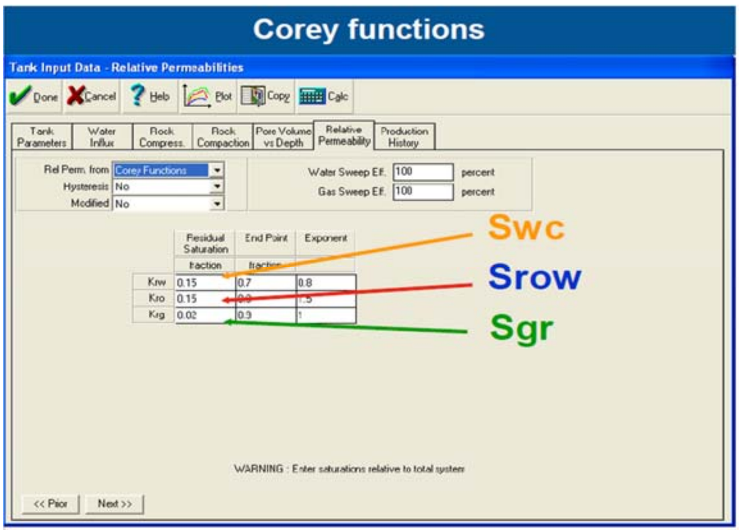
Input/Tank data – pore volume vs. depth

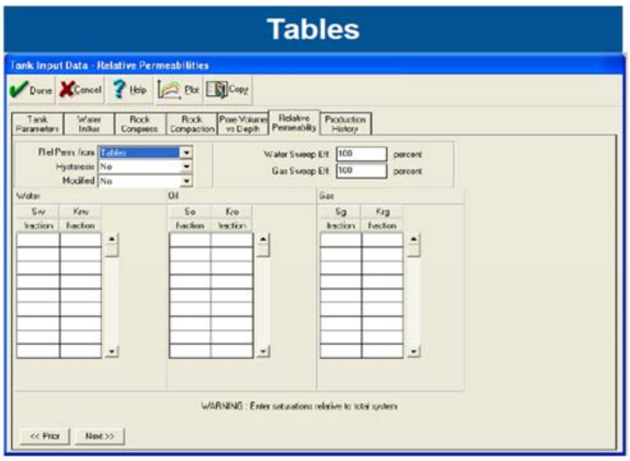
- **Different “Normalized” ‘Pore volume vs. depth’ relationships:**



Input/Tank data – relative permeability

- **2 ways to introduce relative permeability curves:**
  - By using Corey functions
  - By using tables





  - for fluid contacts monitoring
  - only for production prediction module

The MBAL software

- Relative permeability: reminders

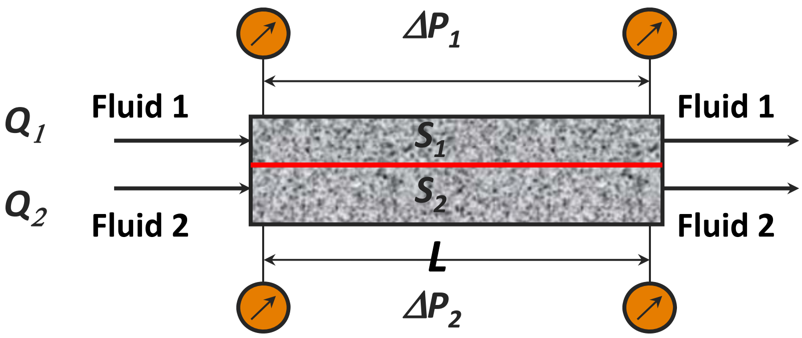
Relative permeability

Darcy's law for multiphase flow

- **In the case of diphasic flow**
  - Monophasic Darcy's law is extended by introducing the **effective permeability** that takes the presence of the other fluid in the porous medium into account

$Q_1 = \frac{k_1}{\mu} A \frac{dP_1}{dx}$ where k_1 is the effective permeability of fluid 1 by respect to fluid 2

$Q_2 = \frac{k_2}{\mu} A \frac{dP_{2w}}{dx}$ where k_2 is the effective permeability of fluid 2 by respect to fluid 1



Definition of relative permeability

- **From the previous extended Darcy's law for multiphasic flow**

$$Q_1 = \frac{kk_{r1}}{\mu} A \frac{dP_1}{dx}$$

$$Q_2 = \frac{kk_{r2}}{\mu} A \frac{dP_{2w}}{dx}$$

where k_{r1} is the relative permeability of fluid 1 by respect to fluid 2 (adimensional)

k_{r2} is the relative permeability of fluid 2 by respect of fluid 1 (adimensional)

k is the monophasic permeability (Darcy)

- **Obviously, we get**

$$k_{r1} = k_1/k$$

$$k_{r2} = k_2/k$$

- **Effective and relative permeabilities depend on the fluid saturations**

$$k_{r1} = k_{r1}(S_1)$$

$$k_{r2} = k_{r2}(S_2)$$

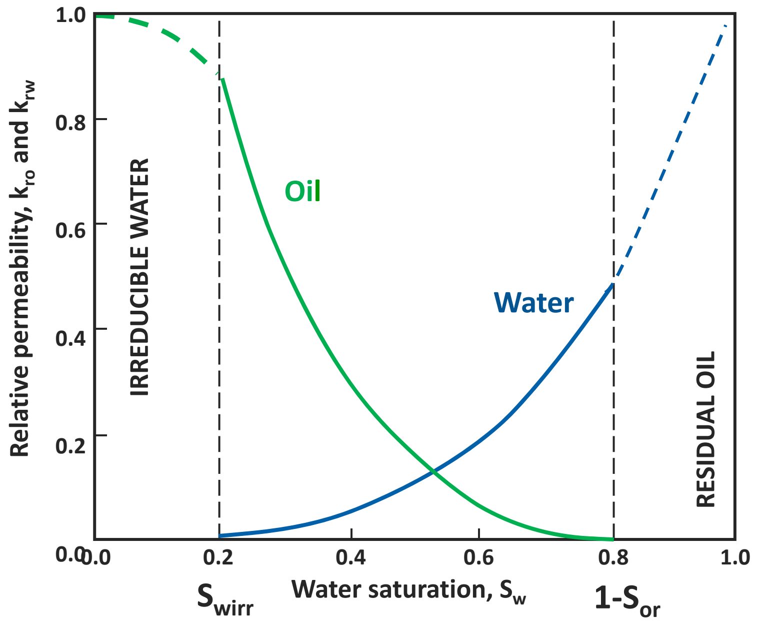
Definitions

- **Absolute permeability**
  - Permeability of a rock completely saturated with one fluid: k_{air}, k_{swi}

- **Effective permeability**
  - Permeability of a rock to one fluid when the rock is only partially saturated with that fluid: $k_o(S_w)$, $k_w(S_w)$
  - Effective permeability is the measurement of the ability of the porous media to conduct one fluid in presence of the others

- **Relative permeability**
  - Ratio of effective permeability to absolute permeability

Relative permeability curves - O/W system



k_r curves **dictate the flow of fluids** in the reservoir and are used for production prediction in MBAL

END POINTS:

S_{wirr} irreducible water saturation → $k_{ro,MAX}$ corresponds au maximum oil Kr (end point)

S_{or} residual oil saturation → $k_{rw,MAX}$ corresponds au maximum oil Kr (end point)

Relative permeability - Corey normalization

- **Saturation normalization**

$S_{wn} = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}}$ normalized water saturation (for relative permeability)

$S_{on} = 1 - S_{wn} = \frac{1 - S_{or} - S_w}{1 - S_{wi} - S_{or}}$ normalized oil saturation

- **Corey normalization for relative permeability**

$k_{rw} = k_{rwmax} S_{wn}{}^{nw}$ $k_{ro} = k_{romax} S_{on}{}^{no}$

where:

$k_{rwmax} = k_{rw}(S_{or})$ maximum relative permeability to water

$k_{romax} = k_{ro}(S_{wirr})$ maximum relative permeability to oil

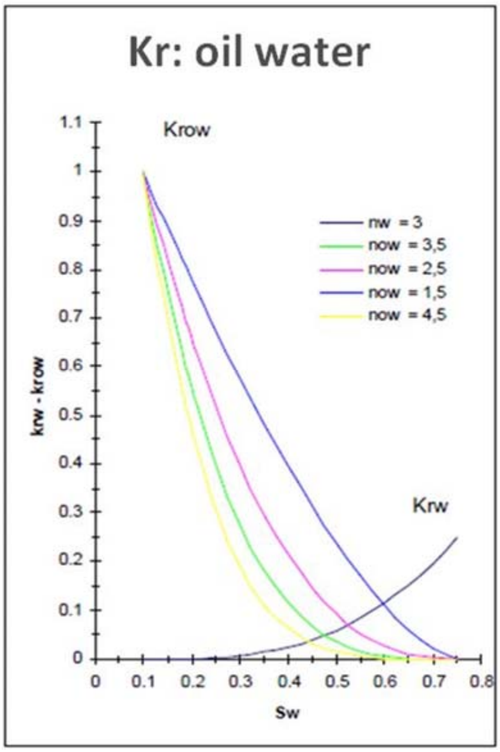
nw Corey coefficient for relative permeability to water

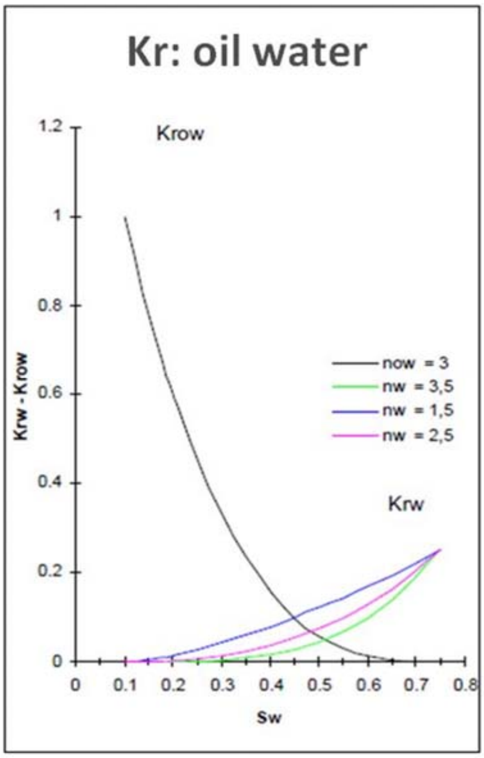
no Corey coefficient for relative permeability to water

- Corey coefficients are always greater or equal to 1 and they control the shape of the relative permeability curves, hence they are related to the porous network (especially pore geometry) and the wettability

Relative permeability

Corey normalization





Warning: the experimental relative permeabilities may differ from the Corey curves

Notes

The MBAL software

- Exercise

Exercise – Reservoir 1

Data:

- **Initial reservoir pressure: 5215 psig**
- **Reservoir temperature: 250 °F**
- **Saturation pressure: 3600 psig**
  - Oil gravity: 35 °API
  - GOR @ Psat: 800 scf/stb
  - Bo @ Psat: 1.456 rb/stb
  - Oil viscosity: 0.31 cP
  - Gas gravity: 0.78
  - Water salinity: 80000 ppm

Exercise – Reservoir 1

Data:

- **Reservoir porosity: 23%**
- **Connate water saturation: 15%**
- **Estimated OOIP : 250 MMstb**
- **Aquifer activity: Radial aquifer, HVE modified model**
  - Reservoir thickness: 100 ft
  - Reservoir radius: 2200 ft
  - ro/ri: 5, θ: 180°, $Kr_{aquifer}$: 20 mD
- **Relative permeabilities – end points:**

	Residual saturation	End point	Corey exponent
Krw	0.15	0.6	1
Kro	0.15	0.8	1
Krg	0.02	0.9	1

Exercise – Reservoir 1

Production data:

(see excel file: reservoir1.xls)

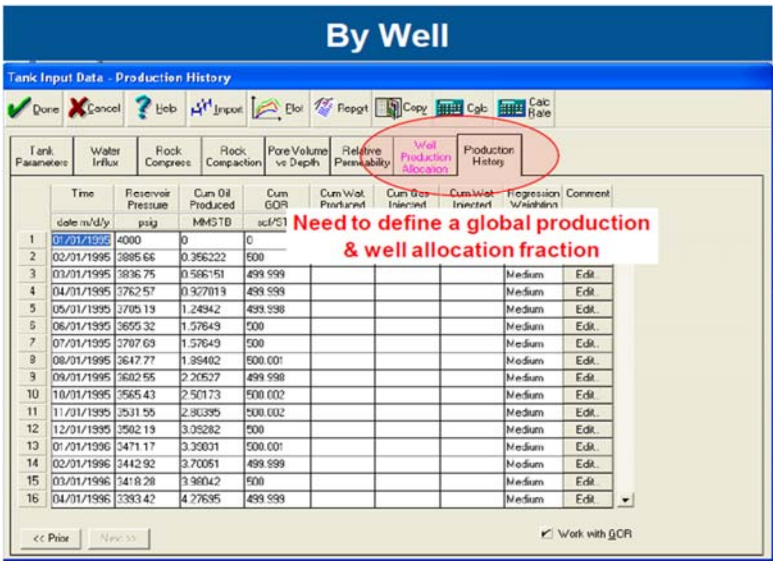
Date	Pressure	Cum Oil	Cum Gas	Cum Water
dd/mm/yy	psig	MMSTB	MMSCF	MMSTB
01/02/2000	5215	0	0	0
16/04/2000	5189,61	0,121533	97,2268	2,22E-05
15/06/2000	5176,5	0,218059	174,448	0,000102242
28/09/2000	5159,4	0,385867	308,693	0,000421904
12/12/2000	5149,07	0,504983	403,986	0,000803664
10/02/2001	5141,26	0,59986	479,888	0,0012039
11/04/2001	5133,65	0,694379	555,503	0,00168874
10/06/2001	5126,16	0,788544	630,835	0,00225786
09/08/2001	5118,73	0,882359	705,888	0,00291071
07/11/2001	5107,68	1,02243	817,946	0,00404538
21/01/2002	5098,53	1,13857	910,855	0,00513165
07/03/2002	5093,07	1,20799	966,395	0,00584408
06/04/2002	5089,43	1,25417	1003,34	0,0063441
21/04/2002	5093,7	1,25417	1003,34	0,0063441
06/05/2002	5097,08	1,25417	1003,34	0,0063441
21/05/2002	5099,89	1,25417	1003,34	0,0063441
20/06/2002	5092,9	1,30039	1040,31	0,00688304
03/09/2002	5079,75	1,41543	1132,34	0,00829563
17/12/2002	5065,04	1,57544	1260,36	0,0104555
17/03/2003	5053,71	1,71173	1369,39	0,0124862
01/05/2003	5048,22	1,77959	1423,67	0,0135643
14/08/2003	5035,65	1,9372	1549,76	0,0162417
27/12/2003	5003,17	2,21089	1768,71	0,021429
25/04/2004	4963	2,57733	2061,86	0,029275
24/07/2004	4939,32	2,84805	2278,44	0,0358439
22/10/2004	4917,52	3,11563	2492,5	0,0430237
04/02/2005	4893,09	3,42402	2739,22	0,0521613
05/04/2005	4879,39	3,59846	2878,77	0,0577414
20/05/2005	4869,2	3,72846	2982,76	0,0620932
01/07/2005	4859,76	3,84914	3079,31	0,0662827

The MBAL software

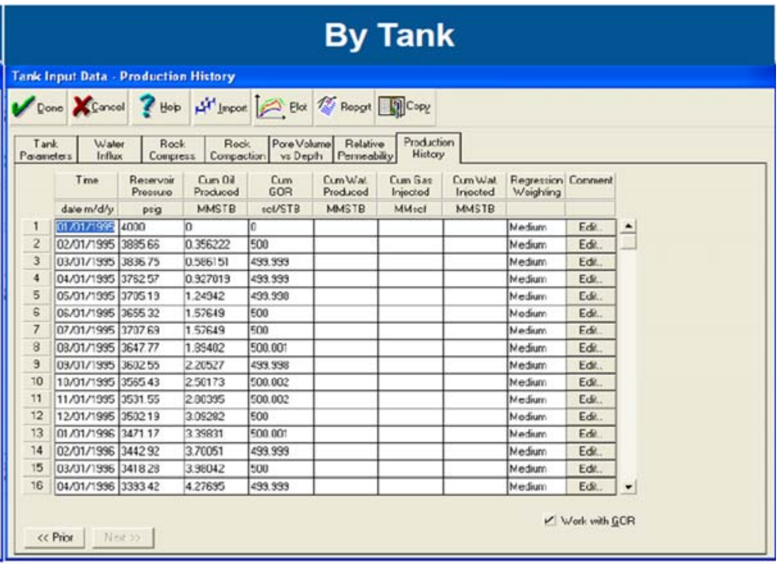
- Production history data and history match

Input production history

- **Depending on the 'Options' module choice, production/injection history can be introduced:**
  - By well
  - By tank



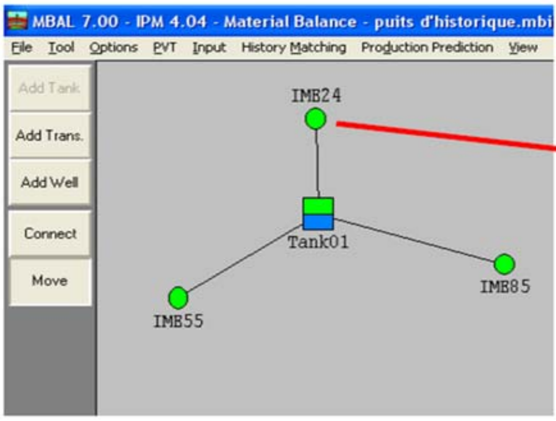
	Time	Reservoir Pressure	Cum Oil Produced	Cum GOR	Cum Wat Produced	Cum Gas Injected	Cum Wat Injected	Regression Weighting	Comment
	date m/d/y	psig	MMSTB	scf/ST					
1	01/01/1995	4000	0	0					
2	02/01/1995	3885.66	0.356222	500					
3	03/01/1995	3836.75	0.586151	499.999				Medium	Edit..
4	04/01/1995	3762.57	0.927019	499.999				Medium	Edit..
5	05/01/1995	3705.19	1.24942	499.998				Medium	Edit..
6	06/01/1995	3655.32	1.57649	500				Medium	Edit..
7	07/01/1995	3707.69	1.57649	500				Medium	Edit..
8	08/01/1995	3647.77	1.89402	500.001				Medium	Edit..
9	09/01/1995	3602.55	2.20527	499.998				Medium	Edit..
10	10/01/1995	3565.43	2.50173	500.002				Medium	Edit..
11	11/01/1995	3531.55	2.80395	500.002				Medium	Edit..
12	12/01/1995	3502.19	3.09282	500				Medium	Edit..
13	01/01/1996	3471.17	3.39831	500.001				Medium	Edit..
14	02/01/1996	3442.92	3.70051	499.999				Medium	Edit..
15	03/01/1996	3418.28	3.98042	500				Medium	Edit..
16	04/01/1996	3393.42	4.27695	499.999				Medium	Edit..

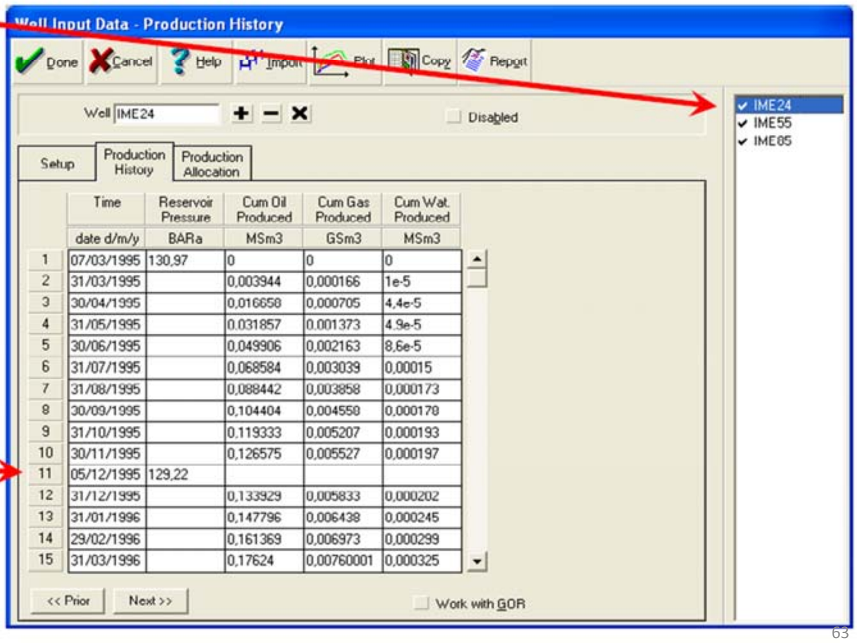


	Time	Reservoir Pressure	Cum Oil Produced	Cum GOR	Cum Wat Produced	Cum Gas Injected	Cum Wat Injected	Regression Weighting	Comment
	date m/d/y	psig	MMSTB	scf/STB	MMSTB	MMscf	MMSTB		
1	01/01/1995	4000	0	0				Medium	Edit..
2	02/01/1995	3885.66	0.356222	500				Medium	Edit..
3	03/01/1995	3836.75	0.586151	499.999				Medium	Edit..
4	04/01/1995	3762.57	0.927019	499.999				Medium	Edit..
5	05/01/1995	3705.19	1.24942	499.998				Medium	Edit..
6	06/01/1995	3655.32	1.57649	500				Medium	Edit..
7	07/01/1995	3707.69	1.57649	500				Medium	Edit..
8	08/01/1995	3647.77	1.89402	500.001				Medium	Edit..
9	09/01/1995	3602.55	2.20527	499.998				Medium	Edit..
10	10/01/1995	3565.43	2.50173	500.002				Medium	Edit..
11	11/01/1995	3531.55	2.80395	500.002				Medium	Edit..
12	12/01/1995	3502.19	3.09282	500				Medium	Edit..
13	01/01/1996	3471.17	3.39831	500.001				Medium	Edit..
14	02/01/1996	3442.92	3.70051	499.999				Medium	Edit..
15	03/01/1996	3418.28	3.98042	500				Medium	Edit..
16	04/01/1996	3393.42	4.27695	499.999				Medium	Edit..

Input production history

▶ Methodology to introduce production history by well – step 1:





	Time (date d/m/y)	Reservoir Pressure (BARa)	Cum Oil Produced (MSm3)	Cum Gas Produced (GSm3)	Cum Wat. Produced (MSm3)
1	07/03/1995	130,97	0	0	0
2	31/03/1995		0,003944	0,000166	1e-5
3	30/04/1995		0,016658	0,000705	4,4e-5
4	31/05/1995		0.031857	0.001373	4.9e-5
5	30/06/1995		0,049906	0,002163	8,6e-5
6	31/07/1995		0,068584	0,003039	0,00015
7	31/08/1995		0,088442	0,003858	0,000173
8	30/09/1995		0,104404	0,004558	0,000178
9	31/10/1995		0.119333	0,005207	0,000193
10	30/11/1995		0,126575	0,005527	0,000197
11	05/12/1995	129,22			
12	31/12/1995		0,133929	0,005833	0,000202
13	31/01/1996		0,147796	0,006438	0,000245
14	29/02/1996		0,161369	0,006973	0,000299
15	31/03/1996		0,17624	0,00760001	0,000325

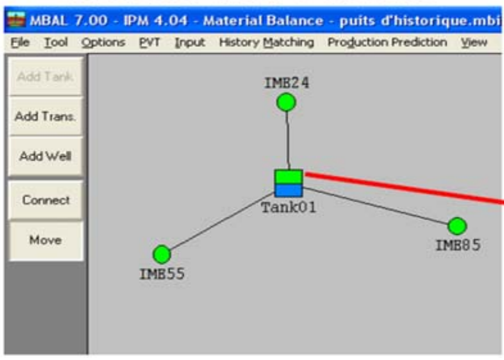
Enter history data by well:

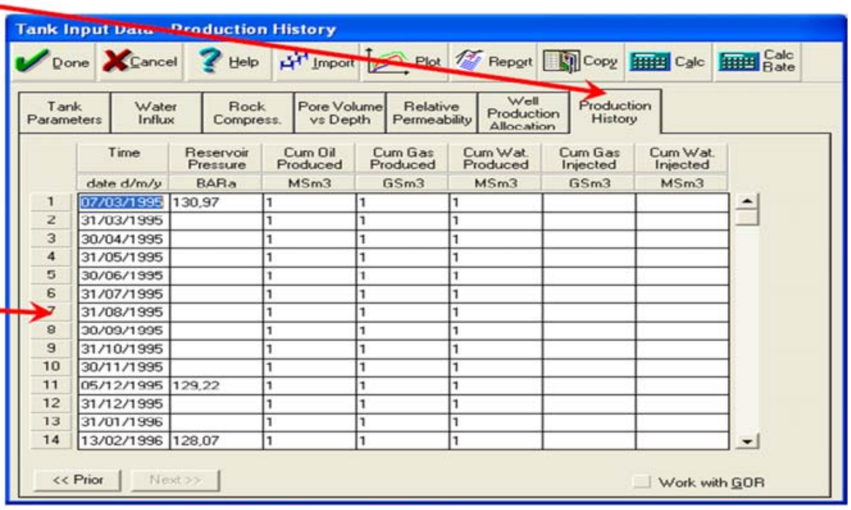
The dates for which a Reservoir Pressure measurement exists do not enter production values

Input production history

▶ Methodology to introduce production history by well – step 2:

A model with 3 wells…



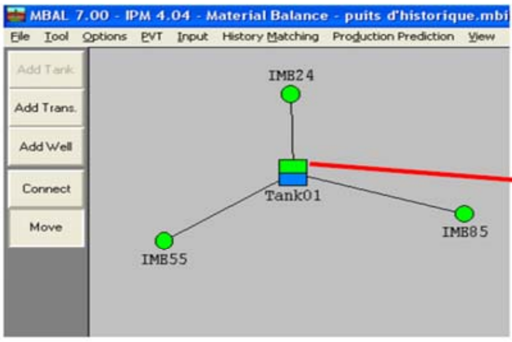


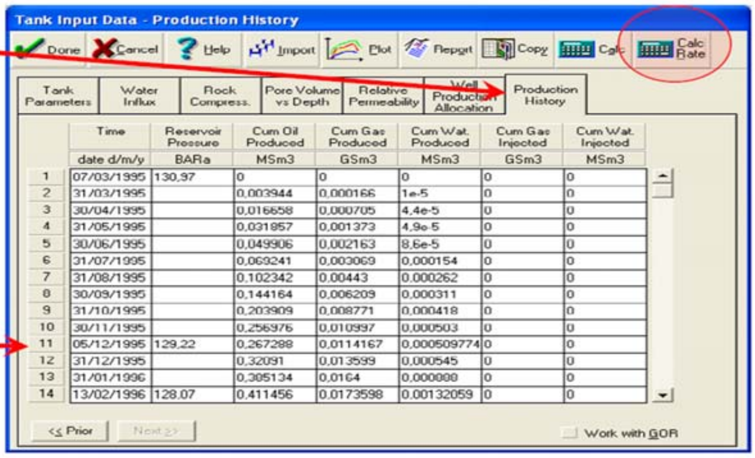
	Time (date d/m/y)	Reservoir Pressure (BARa)	Cum Oil Produced (MSm3)	Cum Gas Produced (GSm3)	Cum Wat. Produced (MSm3)	Cum Gas Injected (GSm3)	Cum Wat. Injected (MSm3)
1	07/03/1995	130,97	1	1	1		
2	31/03/1995		1	1	1		
3	30/04/1995		1	1	1		
4	31/05/1995		1	1	1		
5	30/06/1995		1	1	1		
6	31/07/1995		1	1	1		
7	31/08/1995		1	1	1		
8	30/09/1995		1	1	1		
9	31/10/1995		1	1	1		
10	30/11/1995		1	1	1		
11	05/12/1995	129,22	1	1	1		
12	31/12/1995		1	1	1		
13	31/01/1996		1	1	1		
14	13/02/1996	128,07	1	1	1		

Build on Excel a tank history with only the pressure decline defined by user for the tank + Cumulated produced for each phase = 1

Input production history

▶ **Methodology to introduce production history by well – step 3:**





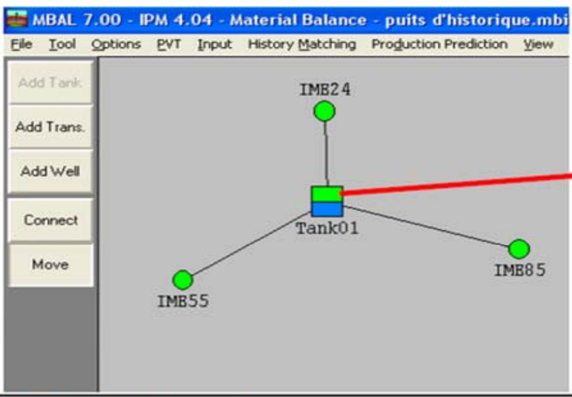
use the **Calc Rate** button to calculate the tank production at every date (even @ PS dates) from the individual wells productions

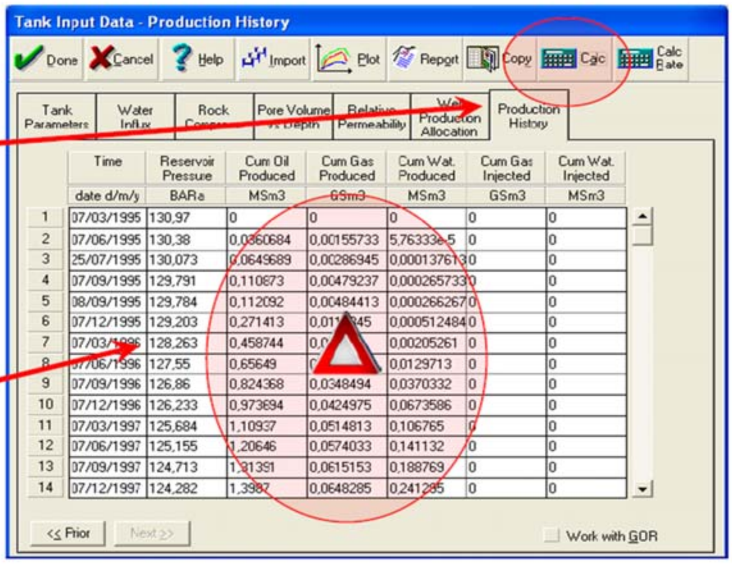
Tank pressure decline is unchanged: the values were previously defined by user
The 'Calc Rate' option re-calculates tank productions if the user changes the wells production allocation ➔ Recommended method

Input production history

▶ **Conclusions on the methodology to introduce production history by well:**

- Define "by hand" the average tank pressure decline, in Excel for example, and then use only the 'Calc Rate' option for tank production generation.
- Use of 'Calc' option not recommended...

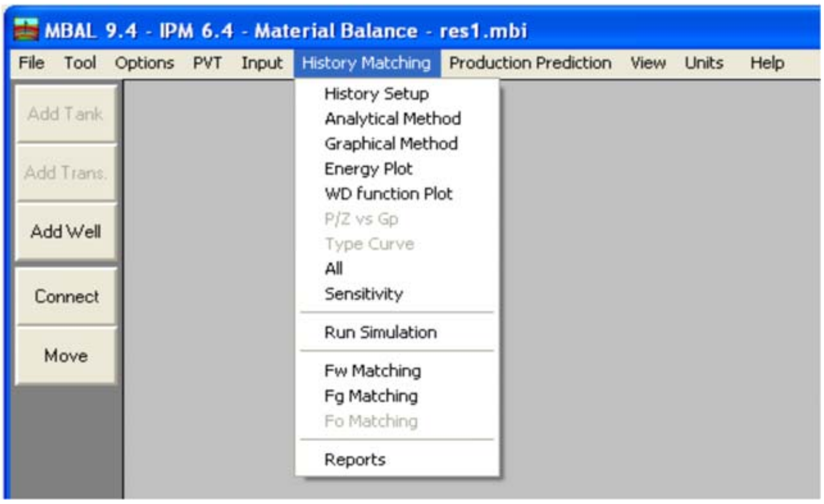




Calculation of an average pressure decline + tank production at every date. If wells were stopped, the estimated decline is not correct

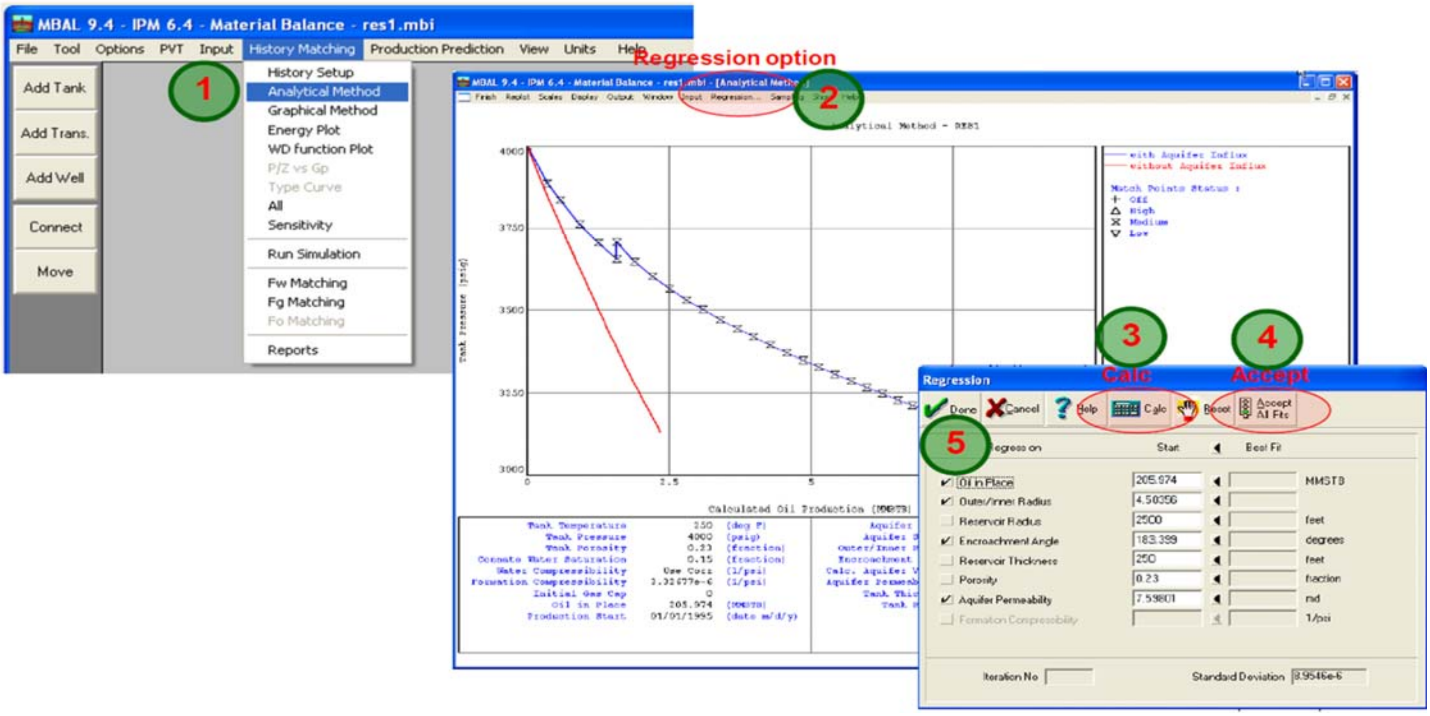
The 'Calc' option is not a recommended method

History matching



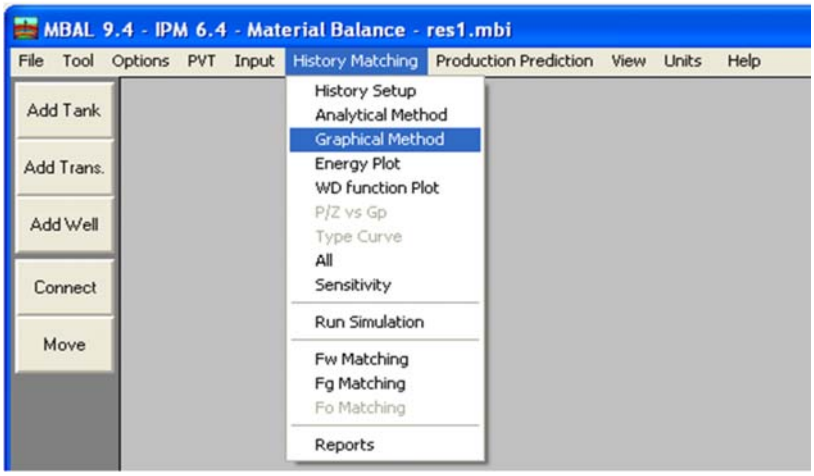
- **Applications/Objectives:**
  - Find parameters to match pressure & production decline data by using
    - The analytical method
    - The graphical method
    - The fractional flow matching for predictions

History matching / Analytical method



- **This method is a plot based method to assist on the estimation of unknown reservoir & aquifer parameters:**
  - The plot shows the response of the model plotted against historical data
  - Calculated values: Oil production & aquifer water influx

History matching / Graphical method



- **The graphical method plot is used to visually determine the different Reservoir and Aquifer parameters**
  - Plots are based on the generalized linear Material Balance Equation:

$$F = N(E_o + mE_g + E_{f,w}) + W_e = NE_t + W_e$$

$$F = G(E_g + E_{f,w}) + W_e = GE_t + W_e$$

History matching/Analytical/Graphical methods

- **Analytical / Graphical methods conclusion / recommendation:**
  - These methods are more qualitative to determine the different reservoir and aquifer parameters.
  - <u>To have a correct match we need both analytical & graphical methods fitted</u>
  - <u>Sometimes all the graphics are difficult to fit but they allow to understand the main physical parameters</u>

The simulation step is only the final step of the matching process

The MBAL software

- Linear material balance / graphical method

Linear Material Balance Equations

- In the years 1963-64, Havlena and Odeh proposed a new method to transform the previous global material balance equation in a linear equation:

$$\boxed{F = N\left(E_o + mE_g + E_{f,w}\right) + \left(W_e\right)B_w}$$

with

F	*Underground withdrawal*
E_o	*Oil expansion & its original dissolved gas*
E_g	*Gas cap expansion*
$E_{f,w}$	*Connate water expansion & pore volume reduction*
N	*OOIP*
W_e	*Aquifer water influx*

Linear Material Balance Equations

- **Underground withdrawal: F**
  - Oil

$$N_p B_o$$

  - Produced gas (dissolved & injected gas)

$$(G_p - N_p R_s - G_i) B_g$$

  - Produced & injected water

$$(W_p - W_i) B_w$$

Linear material balance equations

- **Fluids expansion:**
  - Oil & dissolved gas expansion

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s).B_g$$

  - Gas cap expansion

$$E_g = B_{oi}\left(\frac{B_g}{B_{gi}} - 1\right)$$

  - Rock & water expansion

$$E_{f,w} = (1+m)B_{oi}\left(\frac{C_w S_w + C_f}{1 - S_w}\right)\Delta P$$

Why this linear equation ?...

- This linear equation to have ‘in case’ a quick way to determine:
  - The initial Gas-cap size
  - The OOIP
  - The influence of water influx

In case of initial Gas-cap
(no wat. Inj & neglecting the fluid & rock expansion)

$$\boxed{\frac{F}{E_o} = N + Nm\frac{E_g}{E_o}}$$

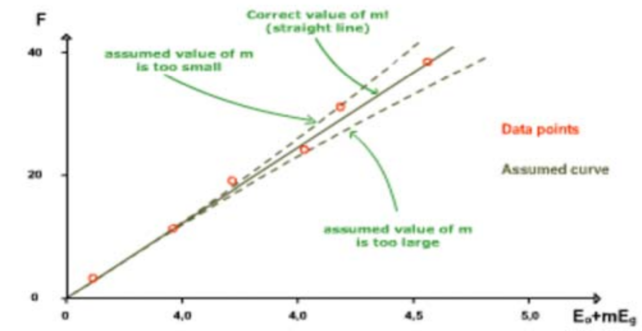
- F vs. E_o+mE_g ➔ determine m
- F/E_o vs. E_g/E_o ➔ determine m & N

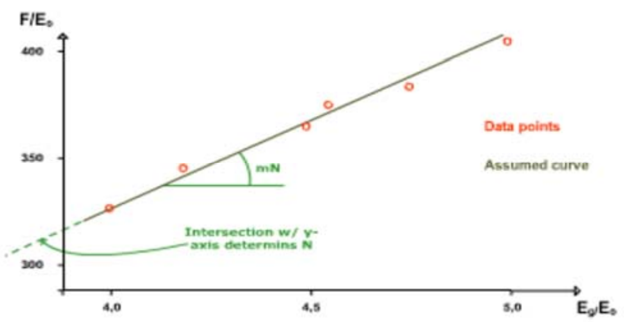
In case of active Aquifer
(no wat. Inj & neglecting the fluid & rock expansion)

$$\boxed{\frac{F}{E_o} = N + \frac{W_e}{E_o}}$$

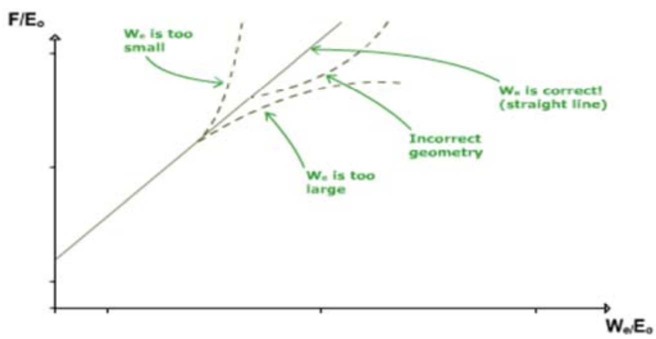
- F/ E_o vs. W_e/E_o ➔ determine W_e

In case of initial Gas-cap
(no wat. Inj & neglecting the fluid & rock expansion)





In case of active Aquifer
(no wat. Inj & neglecting the fluid & rock expansion)



Linear material balance equations & graphics

General case – Campbell plot

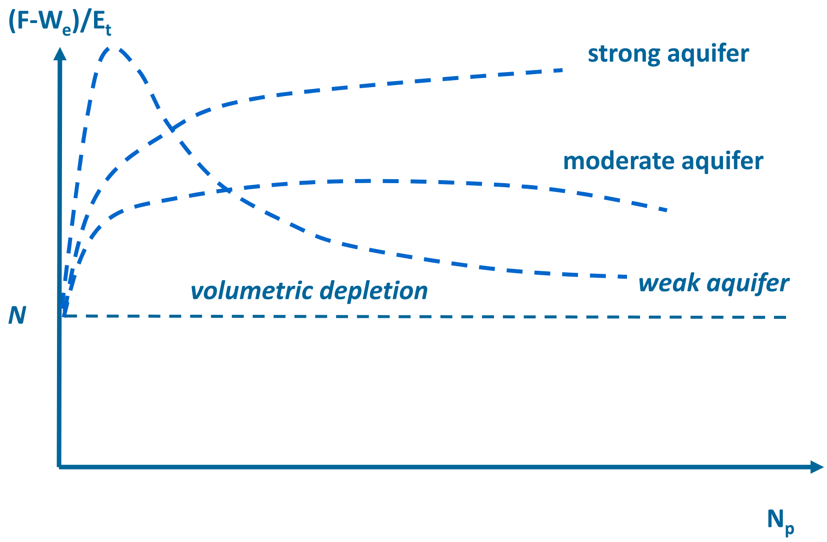
- **In the most general case, MBE writes:**

  $F = N(E_o + mE_g + E_{f,w}) + W_e$ => $(F - W_e)/E_t = N$

  by plotting $(F - W_e)/E_t = f(N_p)$ we may have a straight line of slope 0 and intercept N

  In general, the plot is built without aquifer to check which type of aquifer should be added:

  - strong aquifer => constant pressure boundary
  - moderate aquifer => infinite aquifer
  - weak aquifer => no flow boundary
  - no aquifer => volumetric depletion

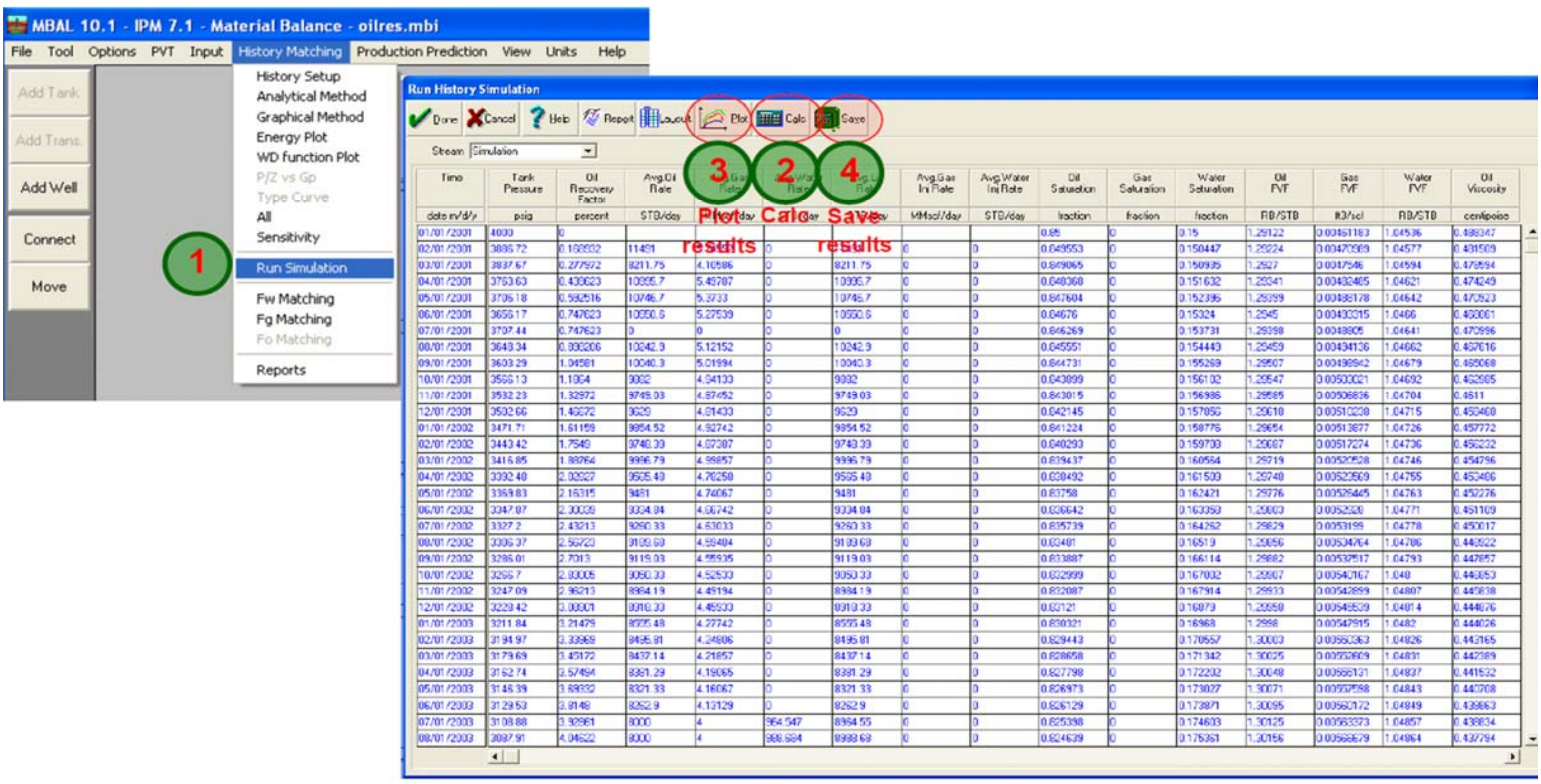


Notes

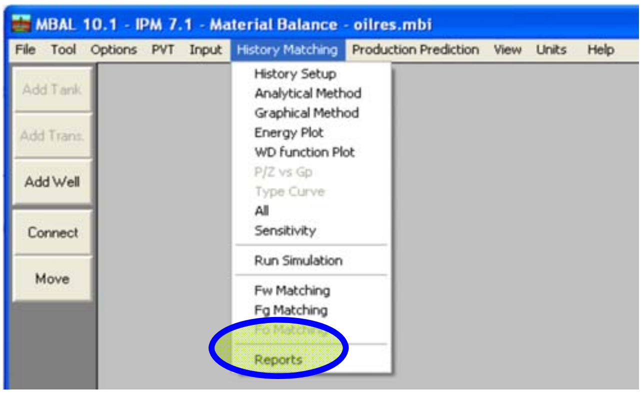
The MBAL software

- Running simulation

History matching / run simulation



History matching / Fractional flow



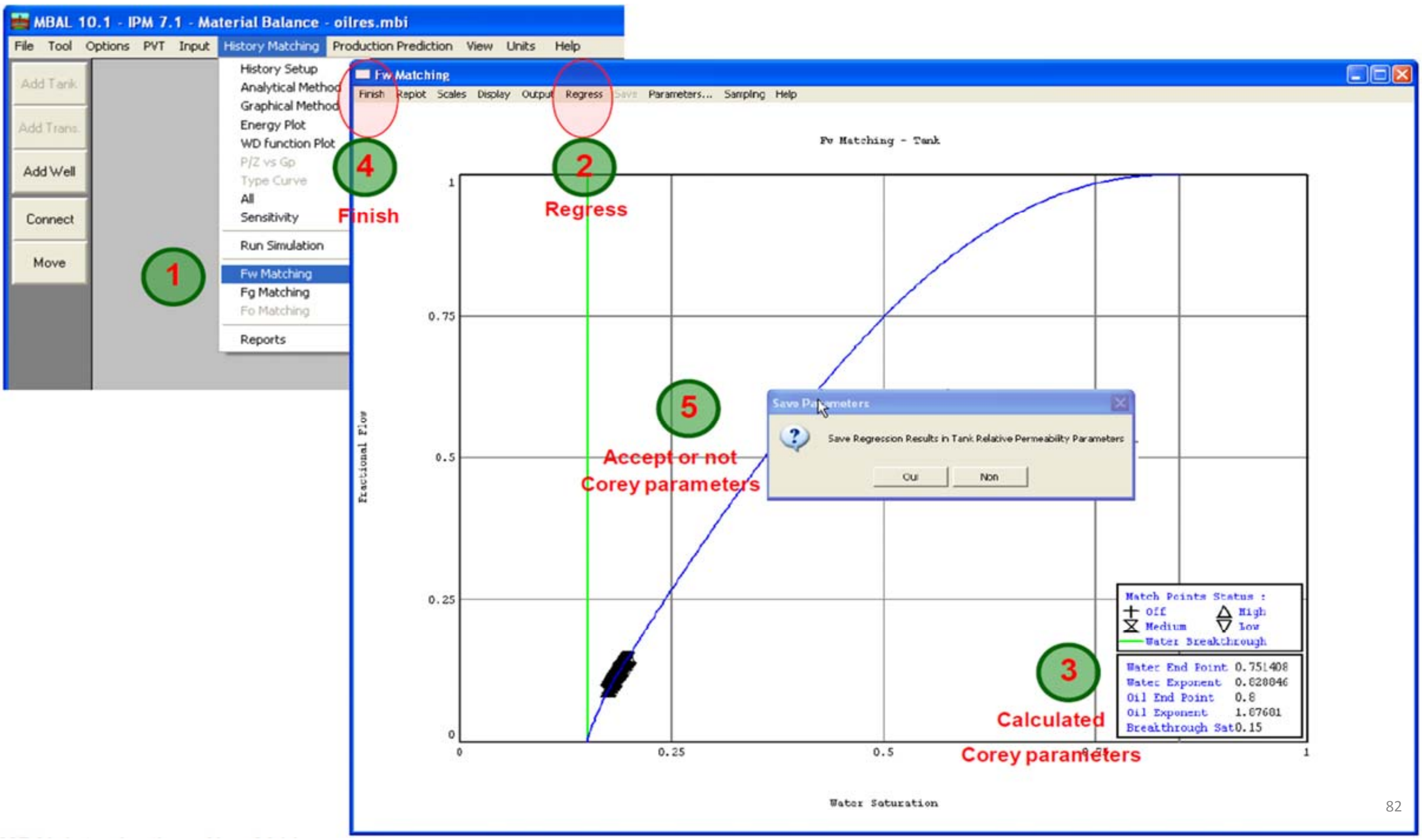
- One of the main difficulties when running a production prediction is to find a set of relative permeability curves that will result in a GOR, WCT or WGR similar to the history.

The purpose of this tool is to generate a set of Corey parameters that will reproduce the observed fractional flows

→ The fractional flow matching can only be used if a simulation has been run

→ It is also important to re-run a simulation each time an input data has changed

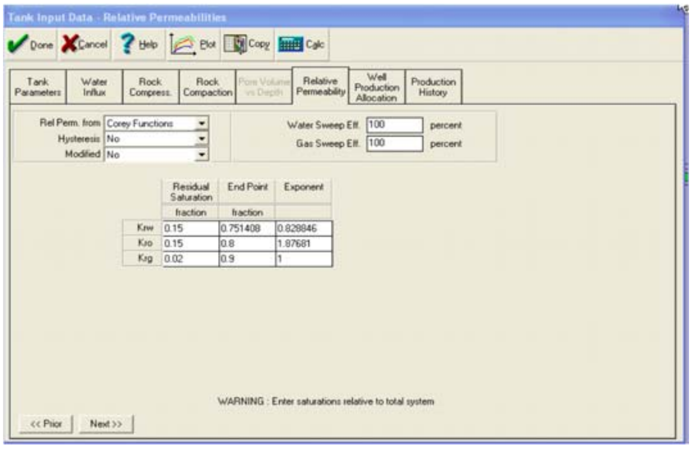
History matching / Fractional flow

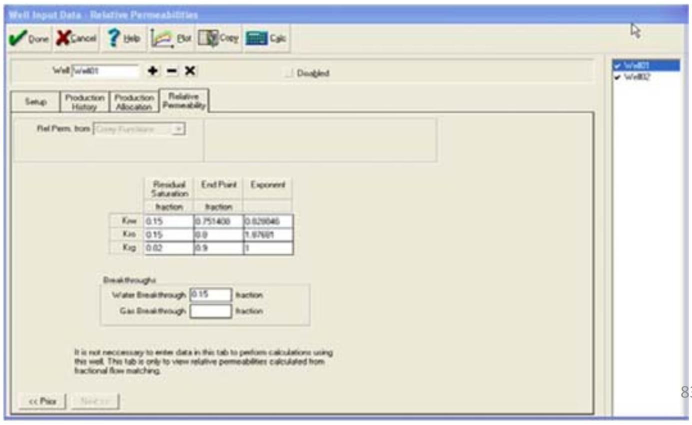


History matching / Fractional flow

- **In case of production history by tank (options menu)**
  - Select the tank in which you want to make a Fw match and then save the Corey parameters in the corresponding tank

- **In case of production history by well (options menu)**
  - Select the tank in which you want to make a Fw match and then save the Corey parameters in the corresponding well





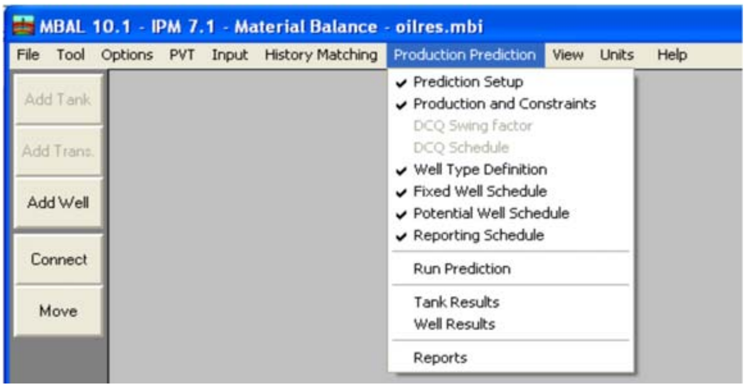
History matching – Methodology

- **Use the analytical method**
- **Use the appropriate graphical method and determine if an aquifer must be introduced → Both analytical and graphical methods must be matched**
- **Test parameters impact:**
  - first the aquifer parameters
  - then the OOIP or gas cap (interdependent parameters)
- **Always check the matching on graphical methods**
- **Run the simulation**
  - Control the match quality: comparison calculated/production pressure & other parameters (contacts, saturations...)
    - if same: good matching
    - if not: restart matching from analytical method (regression)

The MBAL software

- Production prediction

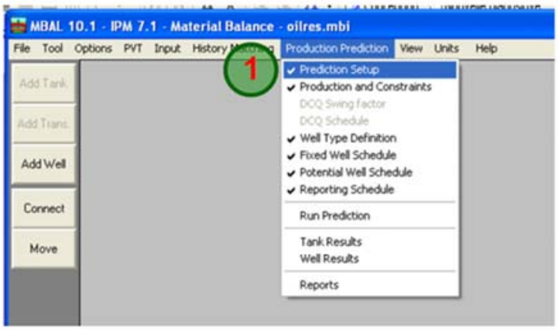
Production prediction

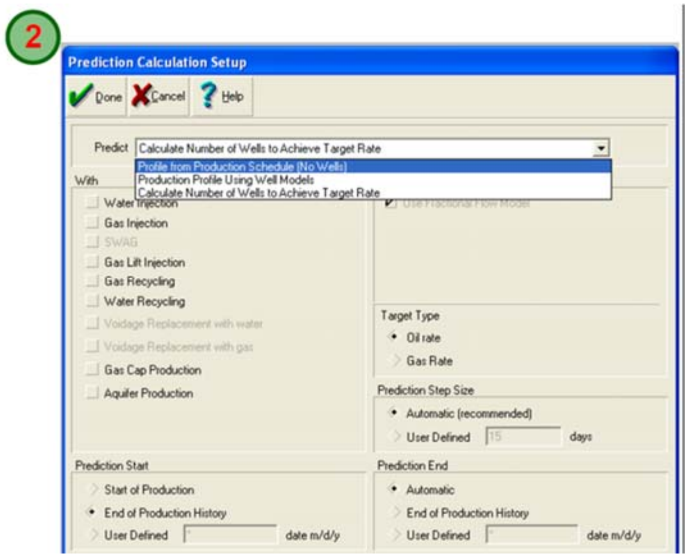


Applications/Objectives:

- Forecast the reservoir performance
  - After a history process to confirm remaining reserves
  - For pre-project field development studies
  - To test other reservoir production/injection strategies:
    - Start/stop gas re-injection
    - Increase/decrease water/gas injection
    - Start/stop existing/new wells

Production prediction / Prediction setup

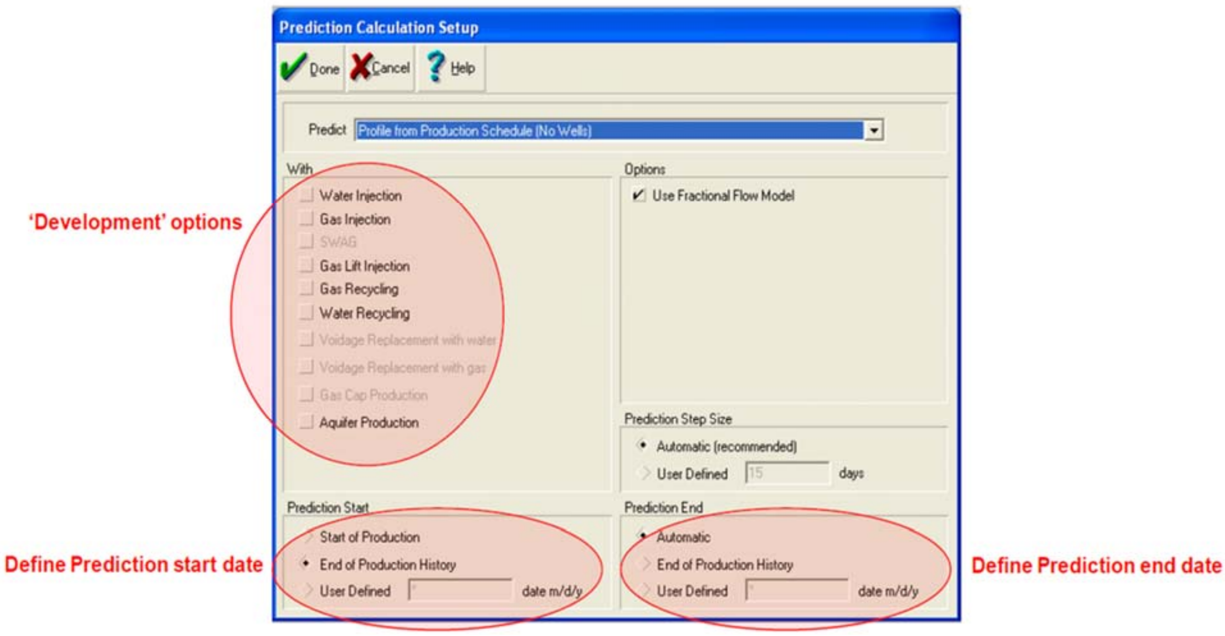




- **3 possibilities to set up the prediction scenario:**
  - Calculate production prediction without wells
    - prediction calculation @ tank (not available for multiple tanks model)
  - Calculate production prediction using well models
    - prediction calculation @ well → need to define a well model with an IPR & a VLP model
  - Calculate Number of wells to achieve a target rate
    - prediction to design a development scenario... → not used a lot...

Prediction setup principle

The user can define manifold constraints independently to be consistent with the development scheme:

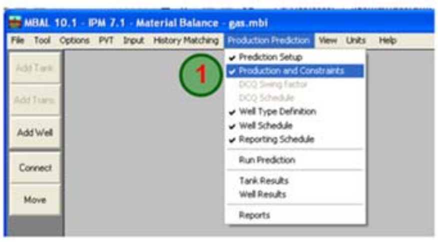


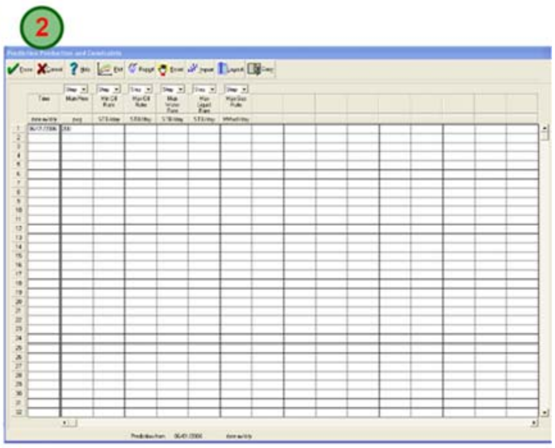
▶**Depending on the 'development' options choice: all the relevant data will be entered in the "Production and Constraints" screen...**

Different production prediction types

- **1st type: Profile from the production schedule (No wells)**
  - Only for mono tank models.
  - The well & manifold are completely ignored → No pressure losses
  - Only the tank and the aquifer are taken into account.
  - The user enters the tank production and injection schedule. The program simulates the tank and aquifer behaviors.
  - Input data:
    - The tank parameters and relative permeabilities,
    - The aquifer type and parameters,
    - The description of the fluids injected (optional),
    - The production schedule for the main phase (e.g. oil for an oil system, gas for a gas or condensate system).
    - The injection schedule (optional)
  - Assumptions:
    - The GOR, CGR, WC, WGR are calculated from the fractional flows using the tank relative permeabilities. These values then define the other phase rates (e.g. water rate for an oil system). Breakthroughs can also be entered to correct the tank relative permeabilities. There is no notion of abandonment.
  - Calculated data:
    - The tank pressure and saturations,
    - Tank rates and cumulative productions for the other phases.
    - Tank average water salinity, gas cap gravity, etc.

Production prediction – Production and constraints

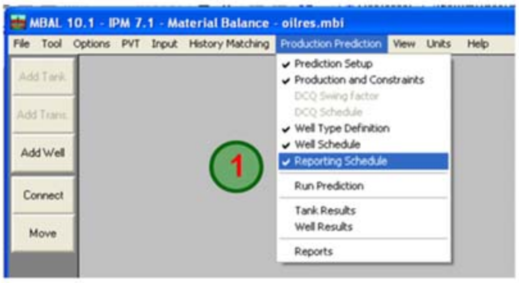


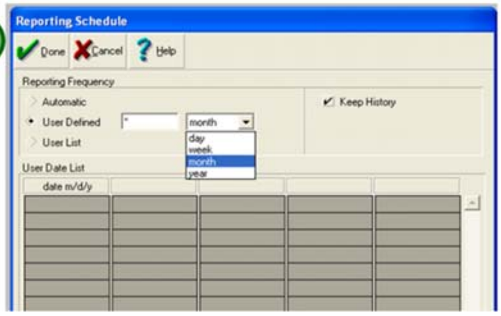


- **The number and content of the columns vary depending on the prediction mode and Predict With options selected in the 'Prediction Setup' dialog box**
- **The following rules are applied:**
  - The column is left entirely empty → There is no constraint on this parameter
  - A column contains only one value → This parameter will remain constant from that point onward

Production prediction – Reporting schedule

▶ Choose the way MBAL reports production prediction calculations

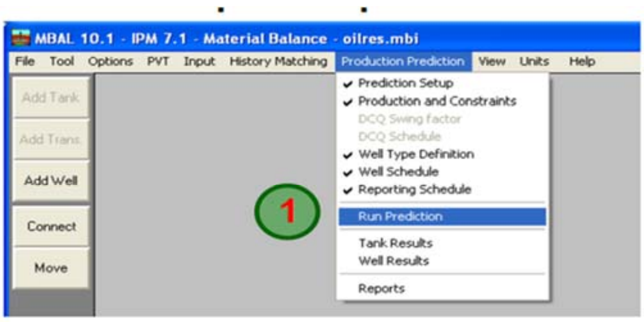




▶ 3 options for prediction reporting

- Automatic
  - The program displays a calculation every 90 days.
- User defined
  - Define any date increment in days, weeks, months or years.
- User list
  - A list of dates can be specified in the table provided. Any number of dates can be entered. The dates can be entered in any order – MBAL will sort the dates into the correct order.
- The option ‘keep history’ will keep history simulation within the production prediction calculation process

Production prediction – Run prediction



Remark:

For now, with MBAL there is no restart option available... MBAL always re-does all the calculations during the complete prediction period...

Enhanced Oil Recovery

Contents

1. Introduction

Introduction

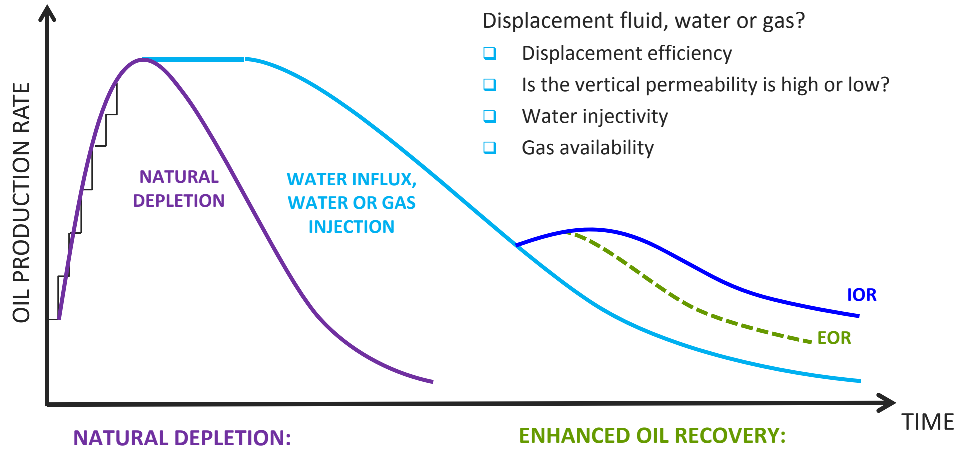
Production mechanisms

- **Conventional methods**
  - Natural energy — **«Primary»**
  - Water injection & immiscible gas injection — **«Secondary»**

- **Unconventional methods**
  - E.O.R.: Thermal processes, Chemical processes, Miscible gas injection — **«Tertiary»**
  - Other technologies: Complex & intelligent wells, Improved reservoir management

Introduction

Production mechanisms



WATER OR GAS INJECTION:

Targeted level of reservoir pressure

When will it be implemented?

Displacement fluid, water or gas?

- Displacement efficiency
- Is the vertical permeability is high or low?
- Water injectivity
- Gas availability

NATURAL DEPLETION:

- Undersaturated oil: P > Psat
- Fluid expansion
- Pore volume compaction

ENHANCED OIL RECOVERY:

- Improvement of the microscopic recovery
- Improvement of the areal sweep efficiency

IMPROVED OIL RECOVERY:

- Embraces all methods resulting in an increased recovery factor: infill drilling, high tech completion, artificial lift, treatment capacity...

Introduction

Sweep efficiency

- **The sweep efficiency corresponds to the recovery factor (at reservoir conditions) for areas undergoing injection**

$$E = RF = \frac{Np.Bo}{Vp.So_i}$$

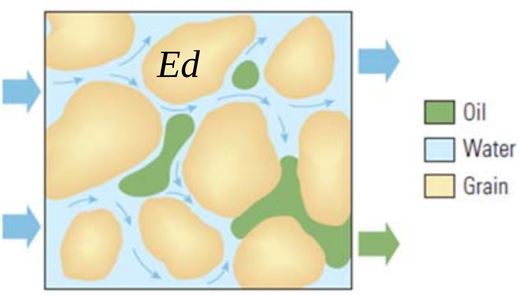
where So_i is the oil saturation at the start of injection

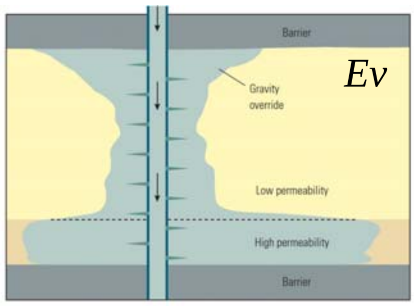
- **The sweep efficiency can be expressed by:** $E = E_d.E_a.E_v$

Ed is the displacement (or microscopic, *Em*) efficiency

Ea is the areal efficiency

Ev is the vertical efficiency



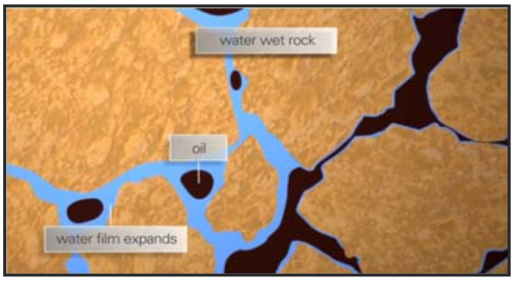


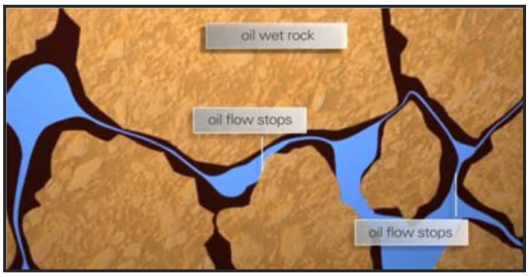
Rifaat Al-Mjeni et al.,
Oilfield Review, SLB. Winter 2010/2011

Introduction
Displacement efficiency

- **The displacement efficiency at the pore scale depends on:**
  - The natural depletion
  - Wettability
  - The mobility ratio: relative permeability & viscosity

$$E_d = \frac{So_i - So}{So_i}$$





BP Videos – YouTube
Exploiting science to increase oil recovery series

At the microscopic scale, oil can be trapped in the middle of pores when water flows around the oil in a water-wet formation. Oil that is connected to flow paths continues to be displaced.

Displacement efficiency – Capillary number

- **The capillary number (Nc) is a dimensionless ratio between the viscous forces and the capillary forces**

$$N_c = \frac{v\mu}{\sigma}$$

The following formula is also valid:

$$N_c = \frac{k\,(\frac{\Delta p}{l})}{\sigma}$$

Where:

$\mu \rightarrow$ Displacing fluid viscosity

$v \rightarrow$ Darcy's velocity

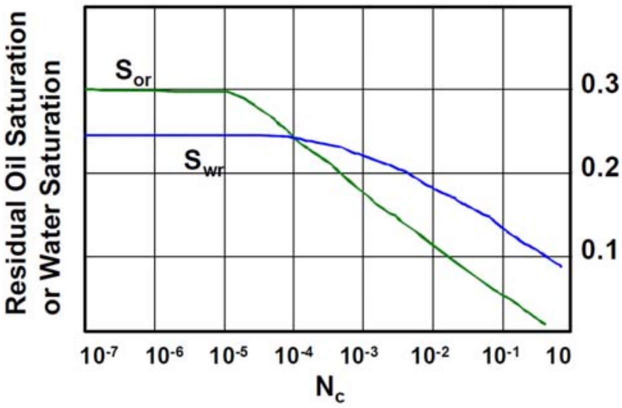
$\sigma \rightarrow$ Interfacial tension (IFT) between the displaced and the displacing fluids.

$k \rightarrow$ Effective permeability to the displaced fluid

$\frac{\Delta p}{l} \rightarrow$ Pressure gradient

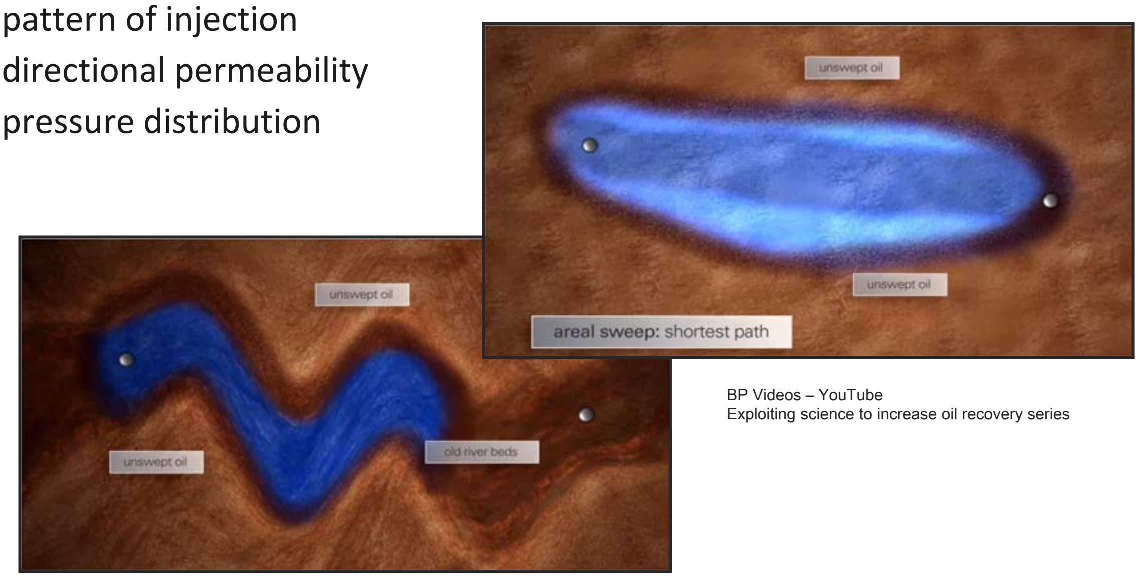
Displacement efficiency – Capillary number

- **A favorable capillary number can be achieved by:**
  - Increasing the displacing fluid viscosity
  - Increasing the pressure gradient
  - Decreasing the IFT
- **Nc to mobilize Sor is much higher than Nc at which it became trapped**
- **Nc vs Sor correlation varies by rock type**
- **Wetting phase residuals can be more difficult to mobilize.**



Areal efficiency

- **Areal efficiency depends on:**
  - The mobility ratio: relative permeability & viscosity
  - The pattern of injection
  - The directional permeability
  - The pressure distribution



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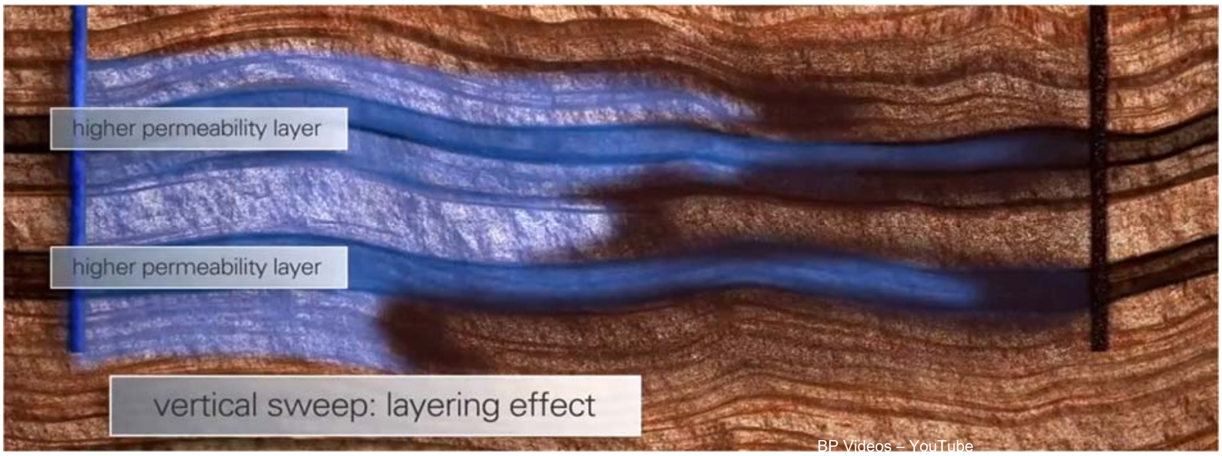
Exploiting science to increase oil recovery series

Oil can be bypassed because of inefficiencies in macroscopic sweep. A pattern flood can be affected by a heterogeneous formation or by fingering of a less viscous injectant into the oil.

Vertical efficiency

- **The vertical efficiency depends on:**
  - Rock properties variation between different flow units



The vertical sweep can be affected by viscous fingering, as well as by the preferential movement of the fluids along a high-permeability thief zone or by gravity override of injection gas or underride of injection water.

EOR principles

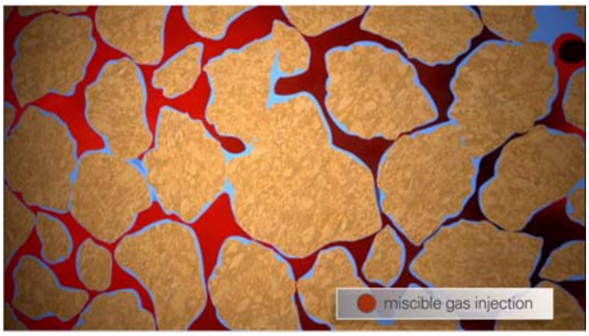
- **Improvement of the displacement efficiency *Ed* by decreasing the residual oil saturation Sor (decrease in the interfacial tension)**
  - Miscible gas injection
  - Surfactant injection – chemical processes

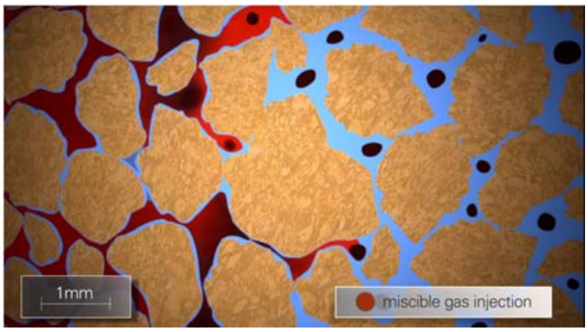
- **Improvement of the volumetric sweep efficiency Ea x Ev**
  - By increasing µw: polymer injection – chemical processes
  - By reducing µo: thermal processes or miscible gas injection (CO_2)

Introduction

Improvement of the displacement efficiency

- **Residual oil saturation might be reduced through miscible gas injection, by reducing the interfacial tension the two phases (oil and gas) reach miscibility and Sor can be reduced until zero.**





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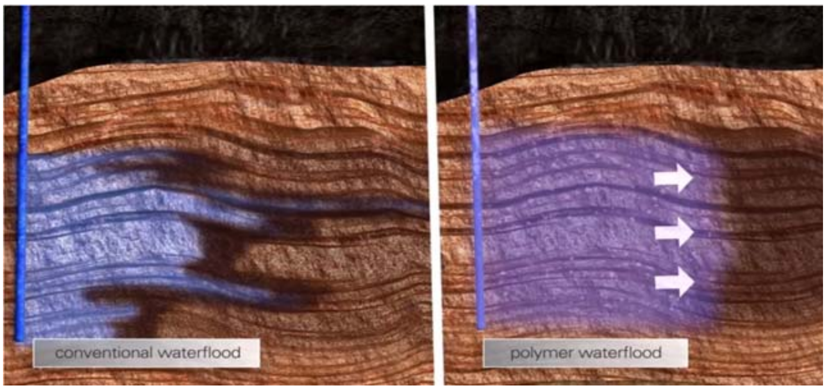
Introduction

Improvement of the volumetric sweep efficiency

- **When reservoir thickness is more important, the interfaces and the "fronts" can be unstable and subsequently distorted (tongue, fingering…)**

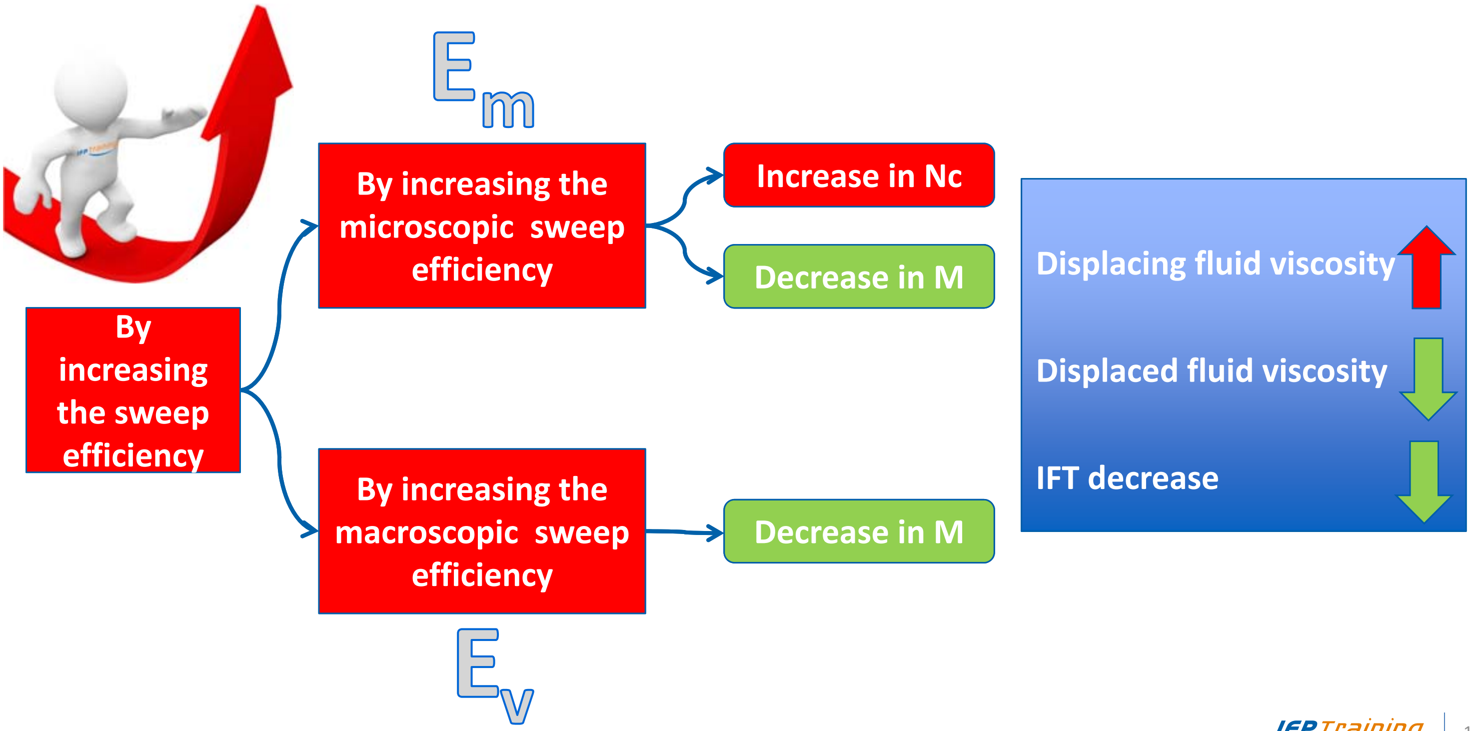


BP Videos – YouTube
Exploiting science to increase oil recovery series

- **The stability of the displacement front is a function of the mobility ratio M**

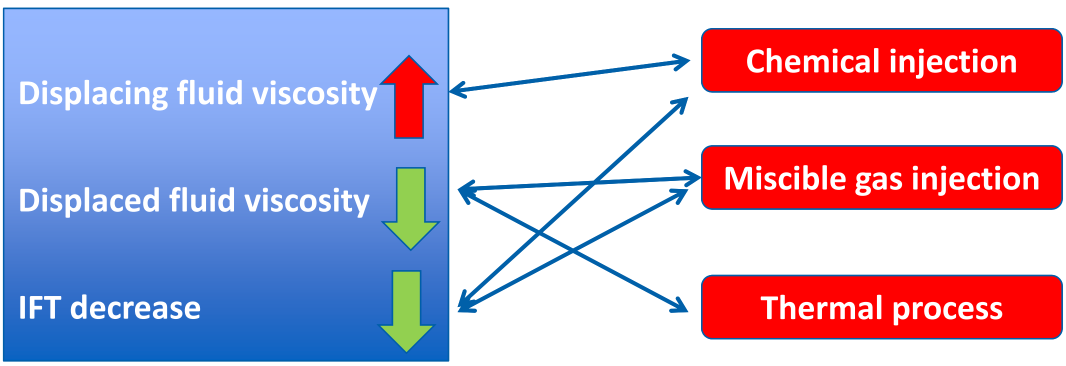
Improving the sweep efficiency – EOR methods

Objectives: How to increase the sweep efficiency (RF)?



Improving the sweep efficiency – EOR methods

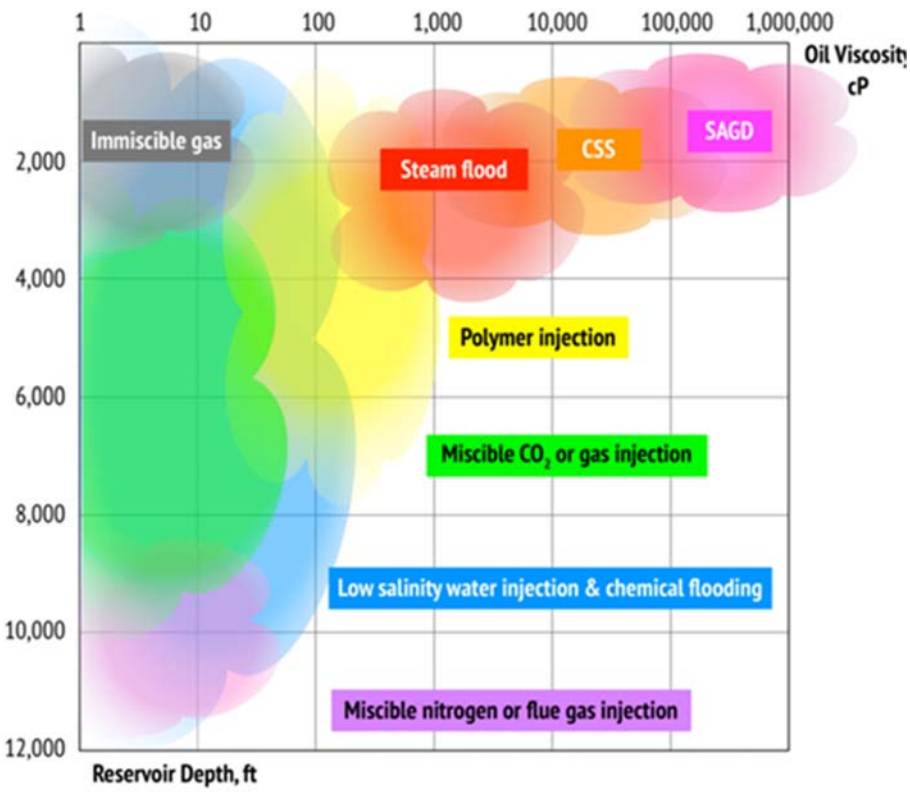
How do different EOR methods help increase the RF?



Introduction
Pilots and studies

- **Since EOR processes are often very expensive, economic studies are very important**
- **Pilot trials for some EOR processes are a must before going full field**
- **The project design should include detailed simulation studies (1D, 2D, 3D)**
  - Numerical simulation of laboratory results
  - Mechanistic cross sections
  - Full field models
- **Specific sophisticated experimental studies are needed**
  - SCAL (wettability, Kr–Pc curves)
  - Waterflood and gasflood at reservoir conditions
  - Advanced PVT experiments to match EOS (e.g. swelling test)

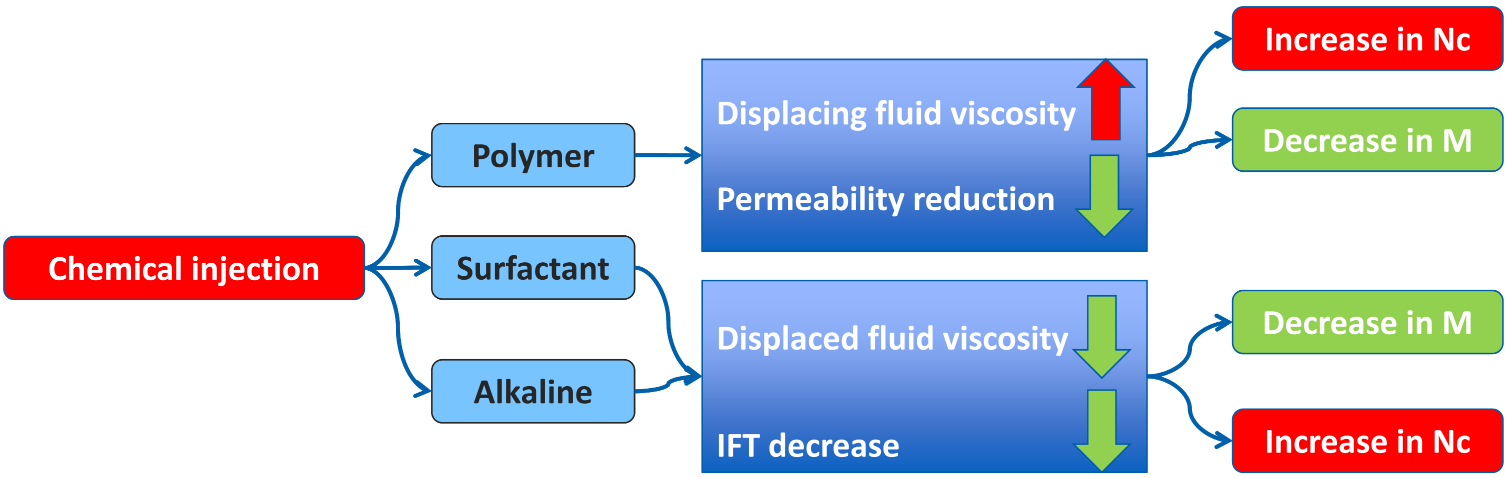
Introduction
Scheme of screening for EOR methods



Shell, 2012

2. Chemical processes

General impact of chemical flooding



Polymers and surfactants

Chemical recovery methods have the following objectives:

- **Polymers: to improve the volumetric sweep efficiency, by reducing the mobility ratio between the fluids injected and the fluids in place**
- **Surfactants: to eliminate or reduce the interfacial tension between oil and water and thus improve the displacement efficiency, i.e. maximize E_d**
- **To act on both phenomena simultaneously**

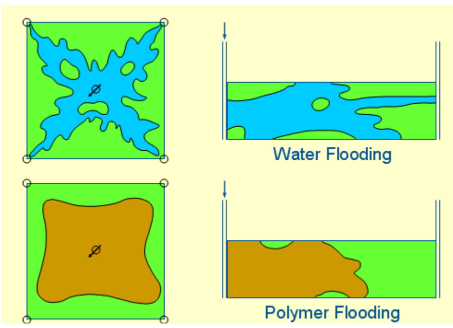
Notes

2. Chemical processes

Polymer flooding

Injection of polymer solutions

- Polymer flooding is the most commonly used chemical enhancement process
- The displacing fluid is viscosified with soluble polymers, which reduces the mobility ratio and leads to a better volumetric sweep efficiency



- The recovery factor may be increased by a modest amount
- Polymer concentrations are between 100 to 1000 ppm and the treatment requires the injection of 15 to 30% PV followed by water injection

Polymer flooding

Resistance and permeability reduction

- **Resistance factor (R_F)**
  - Ratio of brine mobility before polymer injection to that of a single-phase polymer solution flowing at the same conditions. It is an indication of the total mobility lowering contribution of a polymer .

$$R_F = \frac{\lambda_w}{\lambda_p} = \left(\frac{k_w}{k_p}\right)\left(\frac{\mu_p}{\mu_w}\right)$$

- **Permeability reduction factor**

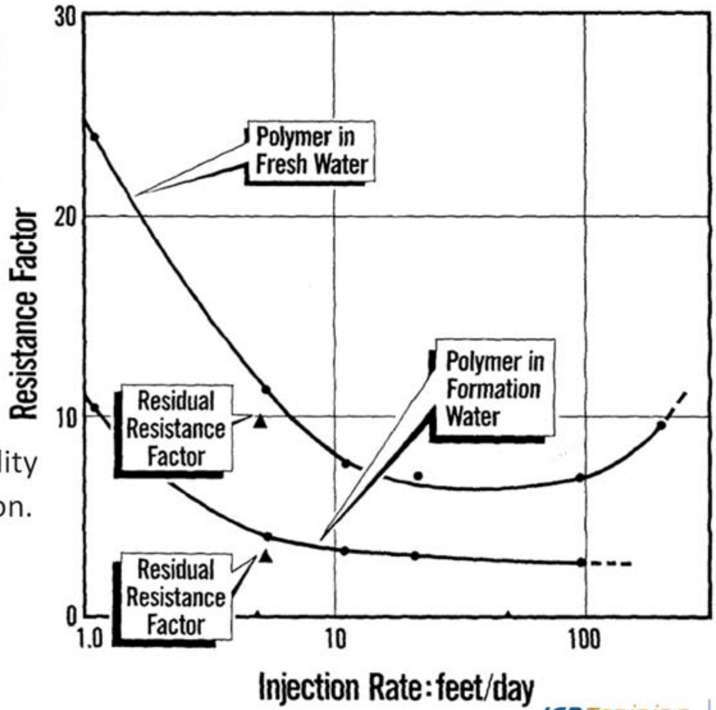
$$R_k = \frac{k_w}{k_p} = \left(\frac{\mu_w}{\mu_p}\right) R_F$$

- **Residual resistance factor**
  - indicates the permanence of the permeability reduction effect caused by the polymer solution.

Brine mobility before polymer flood λ_{wb}

Brine mobility after polymer flood λ_{wa}

$$R_{RF} = \frac{\lambda_{wb}}{\lambda_{wa}}$$



Polymer flooding

Polymer stability

- **Different stabilities:**

1. **Mechanical strength**

   XG solutions are shear stable but not PAM. May be degraded in mixers, valves, pumps, ...

2. **Thermal**

   XG and PAM are stable to above 200°F

3. **Bacteriological**

   XG are sensitive and should be applied with Bactericides (Amine, Formaldehyde, …)

4. **Chemical**

   XG and PAM are compatible with a modest concentration of commonly dissolved ions in oilfield brines

   PAM viscosity sensitive to pH

Polymer flooding

Mechanisms and technical screening

Increasing water viscosity (μ)

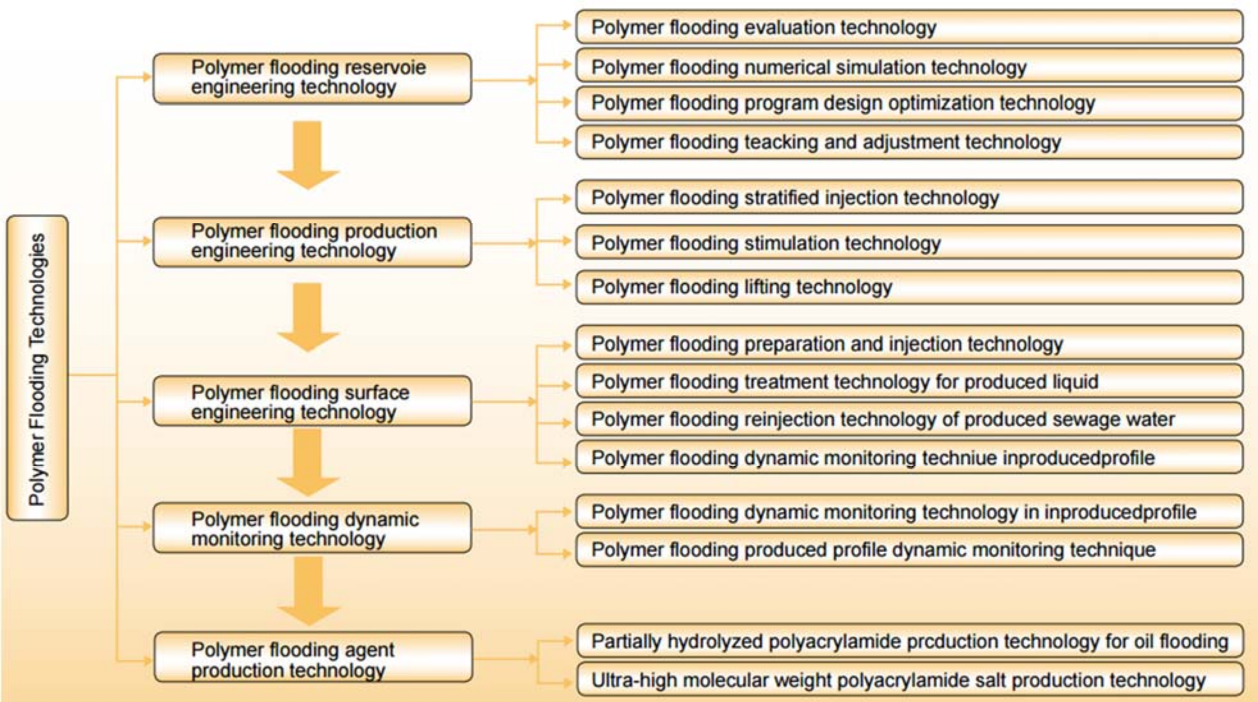
Possibly decreasing water permeability (k)

As a consequence decreasing water mobility (M_w)

Parameters	(Kang, 2011)	(Goodlett, 1986)	(Taber, 1997)	(Al-Bahar, 2004)	(Alvarado, 2002)	Range field applied
Oil Viscosity (cP)	<200	<20	<150	<150	<100	1-80
Oil Gravity (°API)	-	>25	>15	-	>22	14-43
Oil Saturation (%)	-	>10	>50	>60	>50	50-92
Salinity (ppm)	<100,000	<100,000	-	<100,000	<100,000	
Hardness (ppm)	<500	-	-	<1000	<5000	
Wettability	-	water-wet preferred	-	-	-	
Depth (ft)	-	<9000	<9000	-	<9000	1300-9600
Formation Type	-	sandstone preferred	sandstone preferred	-	sandstone preferred	
Temperature (°F)	<200	<200	<200	<158	<200	80-185
Permeability (md)	>10	>20	>10	>50	>50	10-15000
Porosity (%)	-	⩾20	-	-	-	
Net Thickness (ft)	-	>10	-	-	-	
Water Drive	-	-	-	no [a]	no [a]	
GOR	-	-	-	<10	-	

Polymer flooding

Technology



Dacqing field
Polymer Flooding Technology
CNPC, 2011

Polymer flooding

Limitations

- High oil viscosities require a high polymer concentration
- Results are normally better if the polymer flood is started before WOR becomes excessively high
- Clays increase polymer adsorption
- Some heterogeneity is acceptable

Challenges

- Lower injectivity than water injectivity
- The stability of synthetic polymers is lower in case of shear degradation, salinity and divalent ions.
- Biopolymers cost more and are subjected to microbial degradation and have greater potential for wellbore plugging

Notes

2. Chemical processes

Surfactant flooding

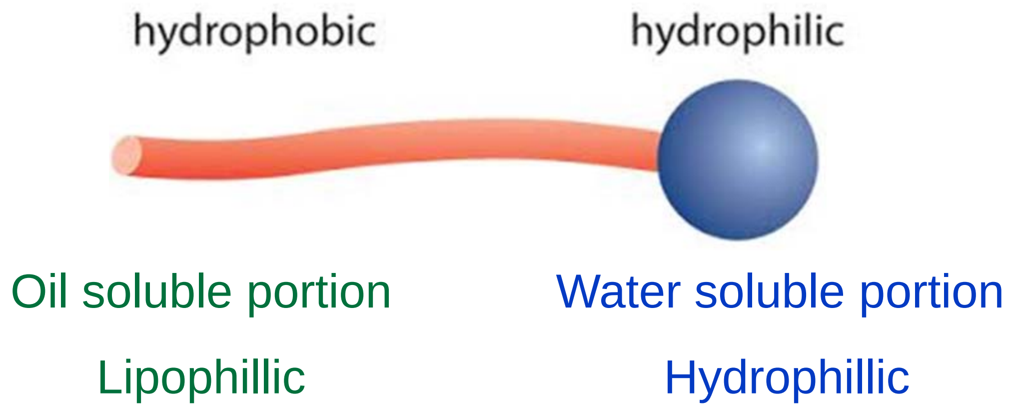
Surfactant flooding

- **Surfactant performance is optimal under a narrow range of conditions**
  - Difficult at high temperature and high salinity
  - Preferably sandstones (some surfactant like alkali may cause precipitation in carbonates reservoir resulting in pore plugging)
  - Surfactants may have low viscosity leading to a poor sweeping efficiency

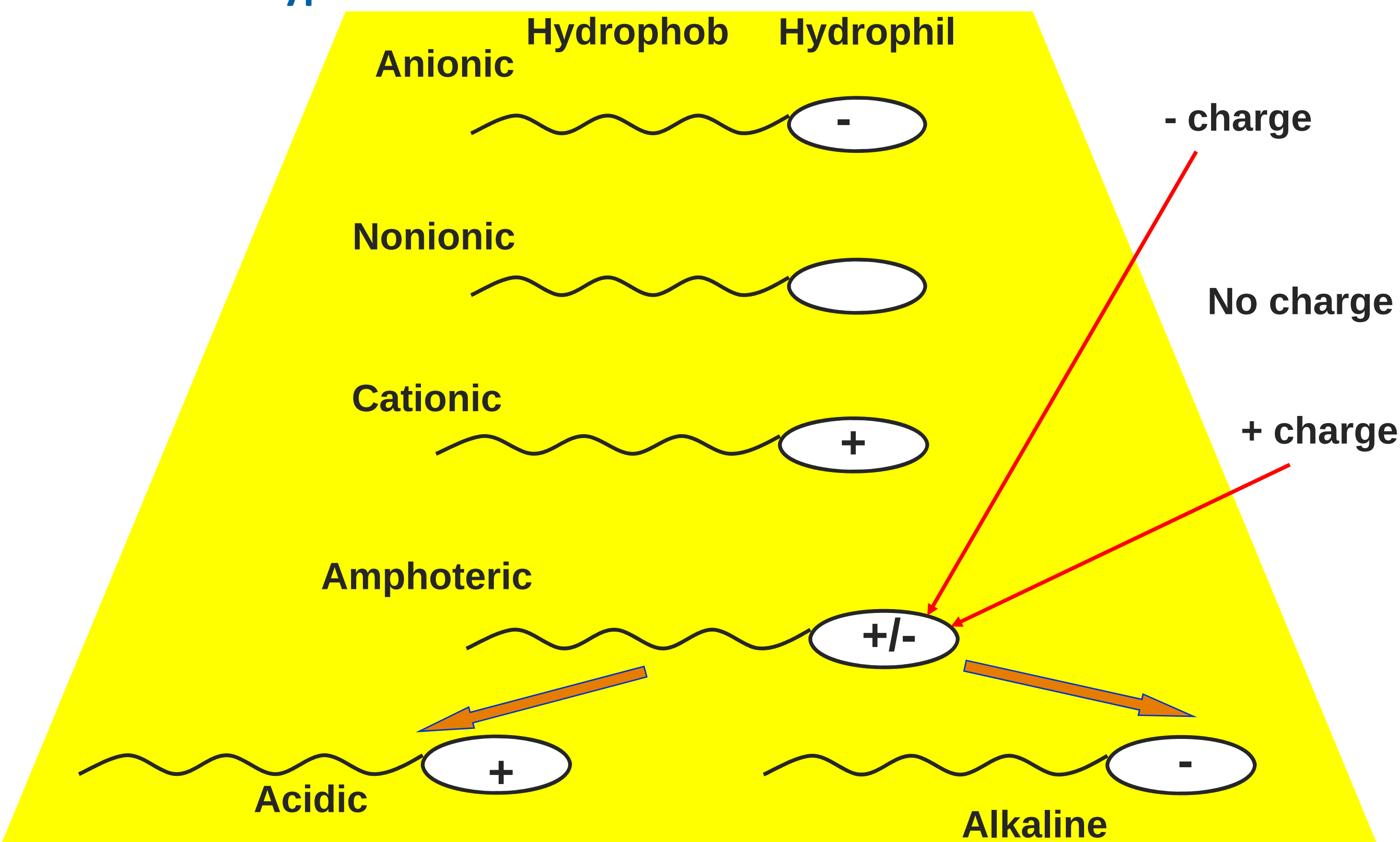
- **However, surfactant flooding has a high potential in terms of oil recovery**
  - Surfactant flooding is generally used with the injection of other chemicals that reduce surfactant losses due to the adsorption on the reservoir rock
  - The latest technology is a combination of Alkaline, Surfactant and Polymer (ASP flood): nowadays, the ASP is the recommended process

What is a surfactant?

- It is a “surface active agent” (very old surfactant is SOAP)
- A chemical compound that combines oil soluble and water soluble properties
- Surfactants are “active” at a surface or interface



Surfactant: 4 types

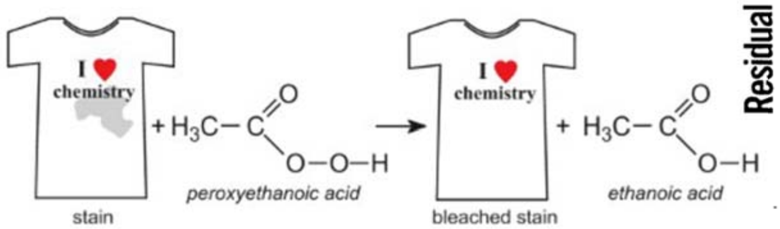


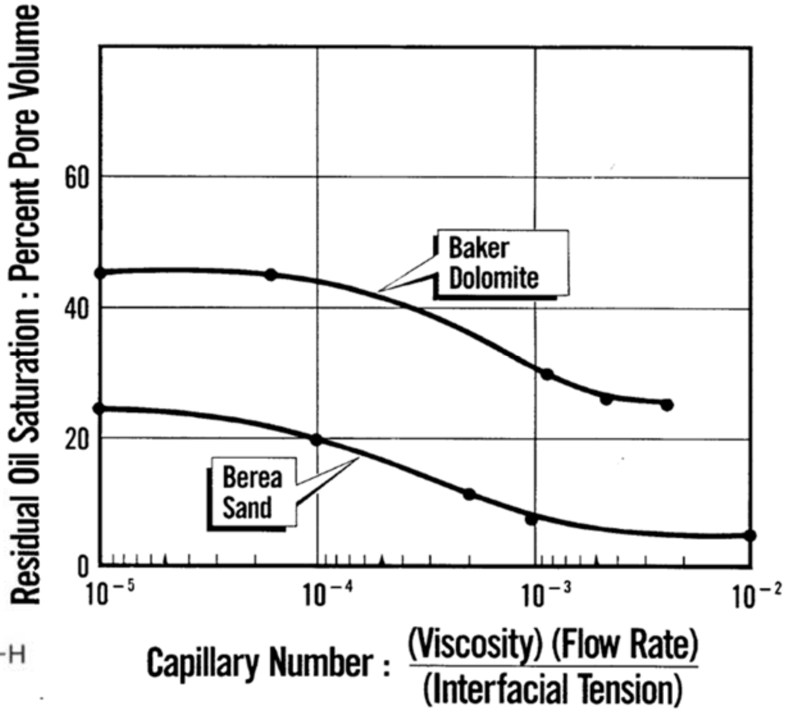
Mechanisms

- Lowering IFT between oil and water ➔ increasing capillary number (Nc)

Increasing the microscopic sweep efficiency

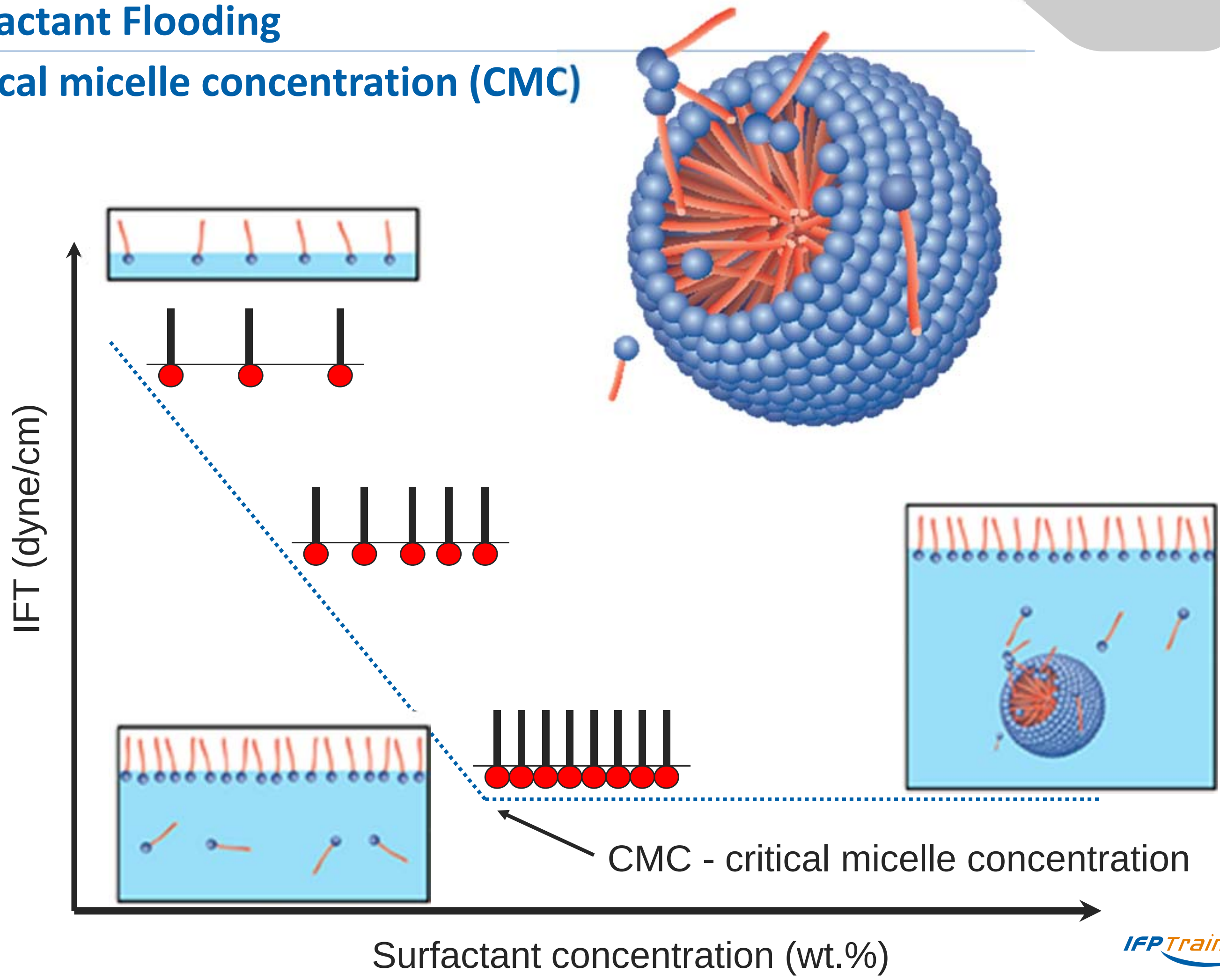
E_m





(Burnett and Dann, 1981)

Critical micelle concentration (CMC)

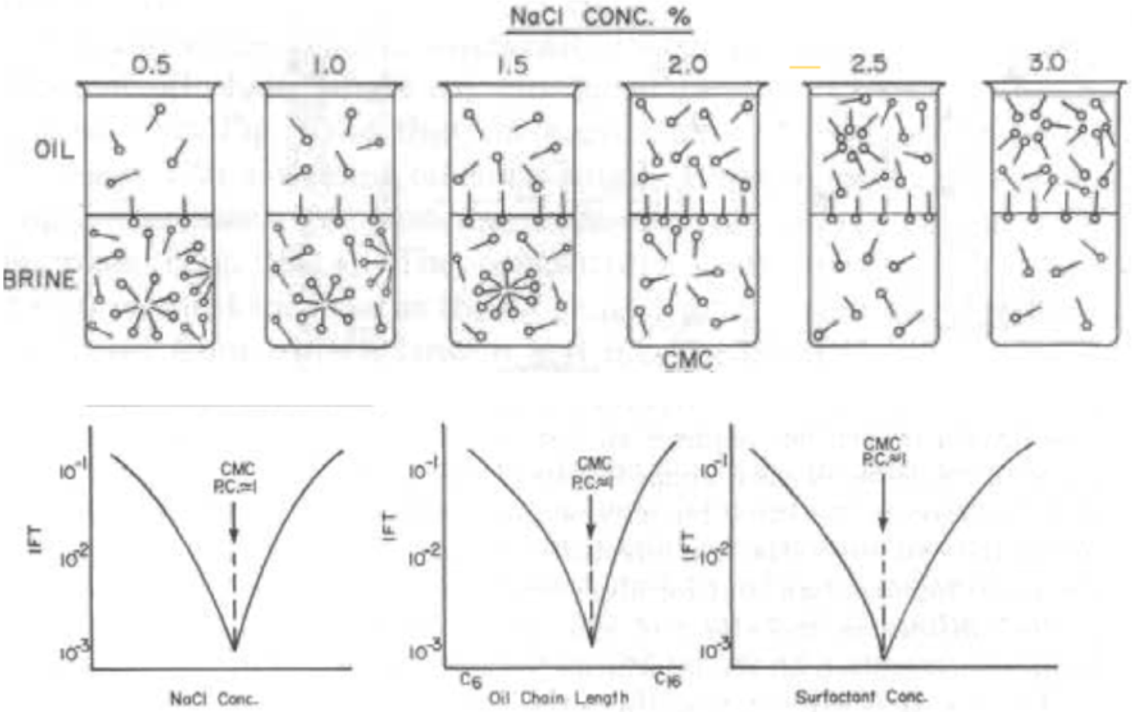


Surfactant Flooding

Critical micelle concentration (CMC)

Parameters affecting CMC

- Salinity
- Oil molecule length
- Surfactant concentration



Surfactant Flooding

Range of oil field characteristics with microemulsion flooding

Property	Range
Depth [ft]	350 - 4550 (107 - 1387 m)
Reservoir Temperature [ºF]	55 - 200 (12.8 - 93 ºC)
Porosity [%]	13 - 32
Permeability [md]	7 - 300+ {avg.}
Type of Reservoir	Unconsolidated to well cemented sandstones, limestones
Formation Water [ppm TDS]	3000 - 160,000 (3000 - 160,000 mg/kg)
Hardness [ppm Ca, Mg, Fe]	25 - 5000 (25 - 5000 mg/kg)
Crude Gravity [ºAPI at 60ºF]	15 - 45 (0.965 - 0.801 g/cm^3)
Crude Viscosity [cp]	3 - 31.7 (3 - 31.7 m Pa*s)
Crude Type	Aromatic-Paraffinic-Naphtenic

Surfactant flooding

- **Micellar polymer injection process**

Mobility buffer

250-2500g/cm^3 polymer

0-1% Alcohol

Stabilizers

Biocide

0-100% V_{pf}

Slug

1-20% Surfactant

0-5% Alcohol

0-5% Cosurfactant

0-90% Oil

Polymer

5-20% V_{pf}

Preflush

Electrolyte (Na^+, Ca^{++}, etc.)

Sacrificial chemicals

0-100% V_{pf}

Surfactant flooding

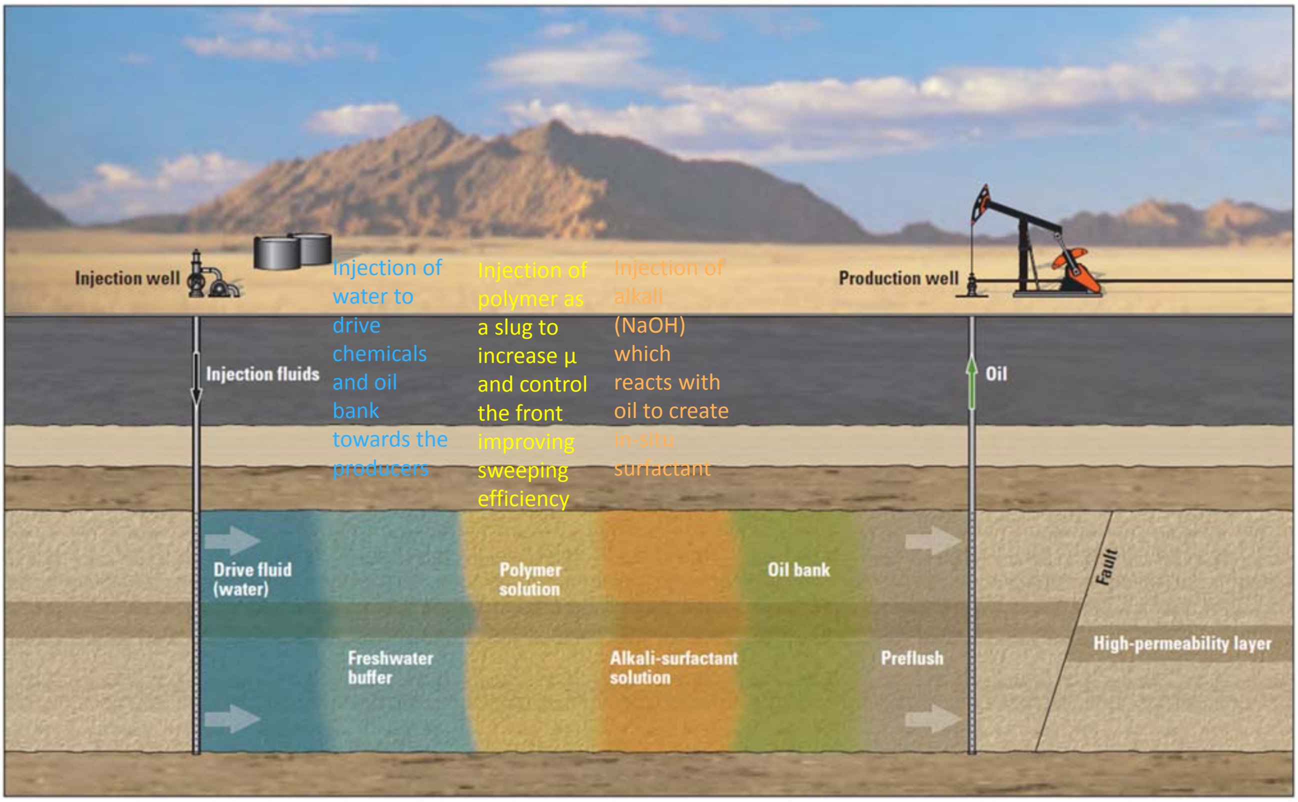
- **Limitations**
  - Low-moderate salinity
  - Moderate temperature
  - Clean sandstone
  - No anhydrite
  - Water wet
  - Med-high permeability
  - Homogeneous
  - Onshore

- **Challenges**
  - High salinity
  - Low or high temperature
  - Carbonate
  - Anhydrite
  - Oil wet
  - Low permeability
  - Fractured
  - Offshore
  - Do research

2. Chemical processes

ASP flooding

ASP flooding



SLB
Oilfield review, 2011

Chemical processes

ASP flooding

- **Principles: combining the best techniques**
  - Injection of alkali (typically sodium hydroxide) which reacts with acidic oil components to create in-situ surfactant (petroleum soap)
  - Simultaneous injection of synthetic surfactant to reduce IFT
  - Injection of a water-soluble polymer both with the alkali-surfactant mixture and as a slug, following the injection of chemicals in order to increase viscosity and control the flooding front, thus improving sweeping efficiency (mobility buffer)
  - Injection of water to drive chemicals and oil bank towards the producers

- **Performances**
  - ASP can theoretically lead to very high recovery factor, up to 90% as shown in laboratory and field pilot
  - ASP is not recommended for carbonate reservoirs (possible reaction of alkali with calcium ions to form precipitates)

Alkali Flooding

Mechanisms

- **Lowering IFT between oil and water ➔ increasing capillary number (N_c)**
- **The difference between micellar flooding and alkaline is that in micellar flooding the surfactant is injected, while in alkaline (or caustic) flooding the surfactant is generated in situ**
- **A high pH chemical EOR method**

NaOH

Alkaline Flooding

How does alkaline generate a surfactant?

- Alkaline method needs an oil with acidic nature
- No acidic species in oil ➔ No surfactant can be generated
- Oil characteristic determination is essential to apply the alkaline method
- The attractiveness of an oil for alkaline flooding is given by its acid number.

  The acid number is the milligrams of potassium hydroxide (KOH) needed to neutralize one gram of crude oil.
- Of course salinity and temperature are also effecting factors

Micellar/polymer, ASP and Alkaline Flooding

Crude Oil Condition	
Gravity: °API	>20
Viscosity: cp	<35
Composition	Light intermediate are desirable for micellar/polymer. Organic acids needed to achieve lower IFT with alkaline methods
Reservoir condition	
Oil saturation: %	>35
Type of formation	Sandstones preferred
Net thickness: ft	Not critical
Average permeability: md	>10
Depth: ft	<9000
Temperature: °F	<200

Taber et al. (1997)

Chemical processes

- **Chemical process objectives may be quite different**
  - Polymer flooding: increases viscosity of the displacing fluid in order to stabilize the front and increase the volumetric efficiency
  - Surfactant flooding: decreases IFT in order to decrease the residual oil saturation and increase the microscopic efficiency
  - Alkali-Surfactant-Polymer flooding combines both Polymer flooding and Surfactant flooding to reach a very high RF, up to 90%
- **Operational conditions**
  - The proper design of the process may be difficult
  - Temperature and salinity may severely decrease the process efficiency
  - Alkali and ASP flooding shall not to be used with carbonates reservoir as they may cause precipitation and pore plugging

Polymer flooding

- **Principles**
  - Displacing fluid is viscosified with soluble polymers, which reduces the mobility ratio and leads to a better volumetric sweep efficiency
- **Limitations**
  - High oil viscosities require a high polymer concentration
  - Results are normally better if the polymer flood is started before WOR becomes excessively high
  - Clays increase polymer adsorption
  - Some heterogeneity is acceptable

Key points to keep in mind

Surfactant flooding

- **Principles**
  - Surfactants: to eliminate or reduce the interfacial tension between oil and water and thus improve the displacement efficiency, i.e. maximize E_d
- **Limitations**
  - Difficult at high temperature and high salinity
  - Preferably sandstones (some surfactant like alkali may cause precipitation in carbonates reservoir resulting in pores plugging)
  - Surfactants may have low viscosity leading to poor sweeping efficiency

Key points to keep in mind

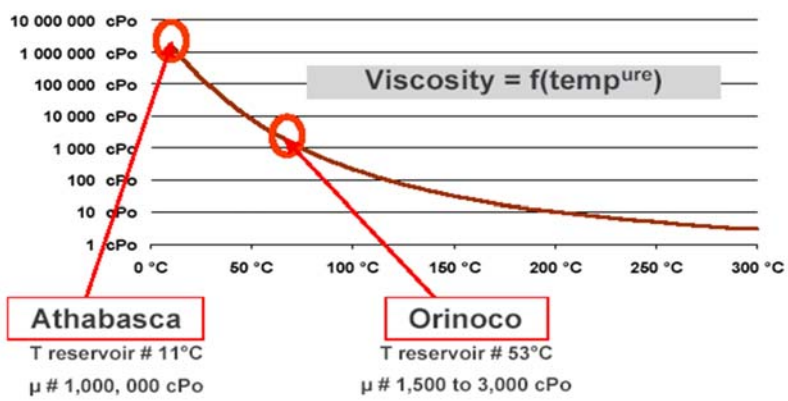
Alkaly-Surfactant-Polymer flooding

- **Principles**
  - Injection of alkali (typically sodium hydroxide) which reacts with acidic oil components to create in-situ surfactant (petroleum soap)
  - Simultaneous injection of a synthetic surfactant to reduce IFT
  - Injection of a water-soluble polymer both with the alkali-surfactant mixture and as a slug following the chemicals injection, in order to increase viscosity and control the flooding front, thus improving sweeping efficiency (mobility buffer)
  - Injection of water to drive chemicals and oil bank towards the producers
- **Limitations**
  - ASP is not recommended for carbonate reservoirs (possible reaction of alkali with calcium ions to form precipitates)

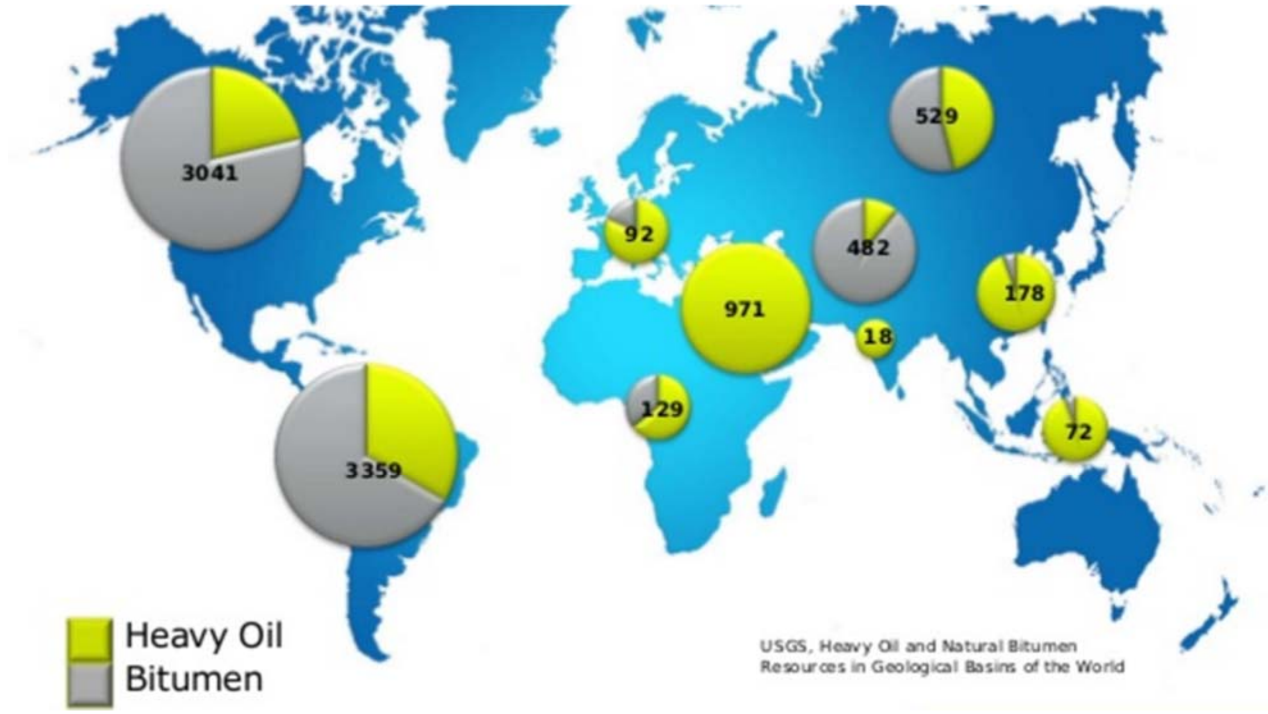
3. Thermal processes

Thermal methods

- **Objectives**
  - To get a lower oil viscosity → higher mobility
  - To improve well productivity
  - To improve the final recovery factor
- **Different Methods**
  - Steam flood
  - In situ combustion
- **These methods are used with viscous oil**



Heavy oil and bitumen deposits (Billion BBL)



Principals of heat transfer

- **Conduction** $$q = k_h A \frac{dT}{dx}$$

q = rate of heat transfer in the x direction, BTU/hr

kh = thermal conductivity, BTU/hr-ft-°F

A = area normal to x direction, ft^2

T = temperature, °F

x = length, ft

- **Convection** $$q = hA(Tf - Ts)$$

h = film heat transfer coefficient, BTU/hr-ft^2-°F

A = area of heat transfer surface, ft^2

Ts = temperature of solid, °F

Tf = temperature of fluid, °F

Thermal methods

Drive mechanisms

- **Oil viscosity reduction**
- **Thermal expansion**
- **Distillation**
- **Solution gas drive**
- **Emulsion drive**

Thermal methods

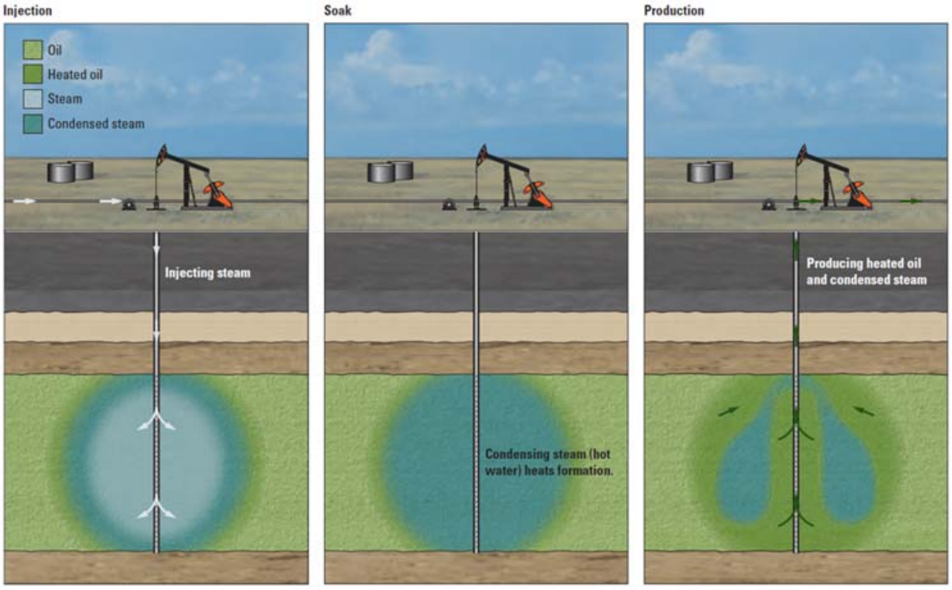
- **Steam flood**
  - Steam generated at the surface is injected into the reservoir through specially distributed injection wells.
  - Different ways of implementation:
    - Cyclic steam injection (Huff and Puff),
    - Continuous steam flood,
    - Steam assisted gravity drainage

Steam injection
Several methods

- **Cyclic steam injection (huff and puff)**
  - Injection of steam into one well (10 days - 1 month)
  - Soaking period: well shut-in (1 - 10 days)
  - Production from the stimulated well (3 months - 1 year)
  - Stimulates production, accelerates depletion
  - Not a recovery technique except in specific cases
- **Steam drive**
  - Continuous injection of steam into injectors
  - Oil pushed to producers
  - Recovery technique
  - Often applied after depletion by several “huff and puff” cycles
- **SAGD process**
  - Steam assisted gravity drainage
  - Continuous injection of steam into horizontal wells
  - Oil produced by gravity in horizontal wells located below the injectors

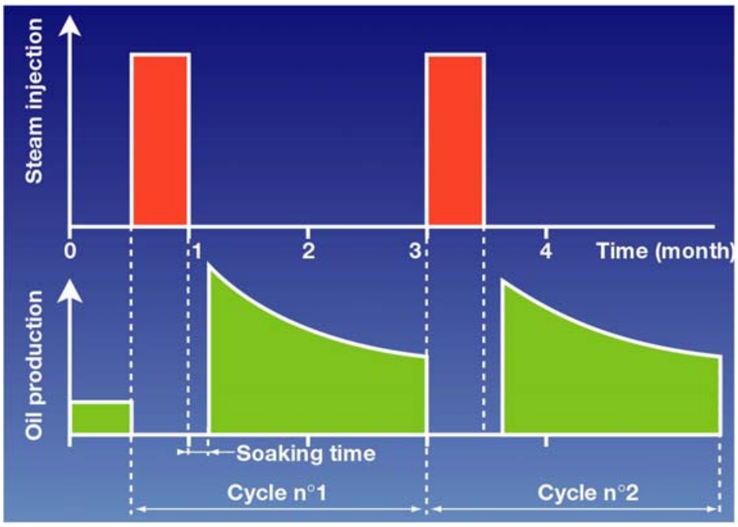
Cyclic steam stimulation

- **High pressure steam injected during several weeks --> heating of the oil, reduction of viscosity**
- **Soak period during several weeks**
- **Pumping of the oil up to the surface**
- **When production declines: switch back to injection**



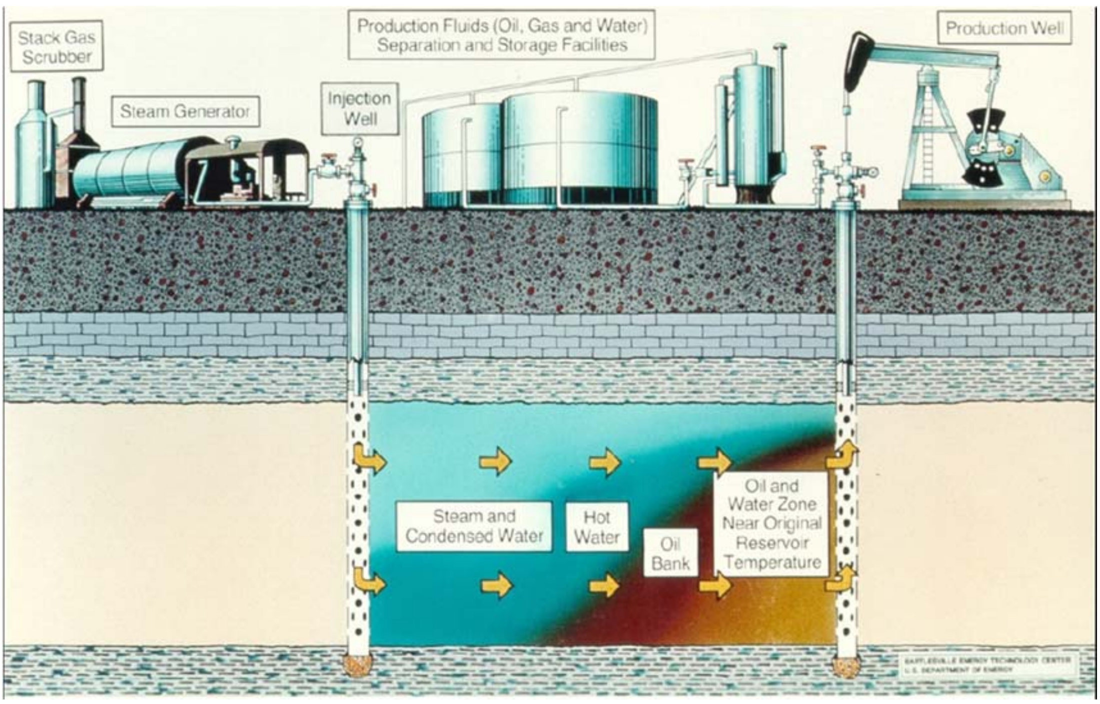
Cyclic Steam Stimulation

- **Proven technology**
- **Examples:**
  - Canada: Cold Lake, Wolf Lake, Primrose
  - Venezuela: Maracaibo area
  - California: Kern River
- **Operating costs: 4-5 US$/bbl**
- **Drawbacks:**
  - Only stimulation around the wellbore
  - Limited recovery factor (15-20%)
  - Energy consumption and GHG emission



Continuous steamflood

- **High-temperature steam is continuously injected into the reservoir**
- **As the steam looses heat to the formation, it condenses into hot water**
- **Steam and hot water drive to move the oil to production wells**



Continuous steamflood

- **As the formation heats, oil recovery is increased by:**
  - The viscosity reduction, increasing oil mobility
  - The expansion or swelling of the oil
  - The vaporization of lighter fractions of the oil. The fractions move ahead into the cooler formation where they condense and form a solvent or miscible bank
  - Condensed water forms a waterflood

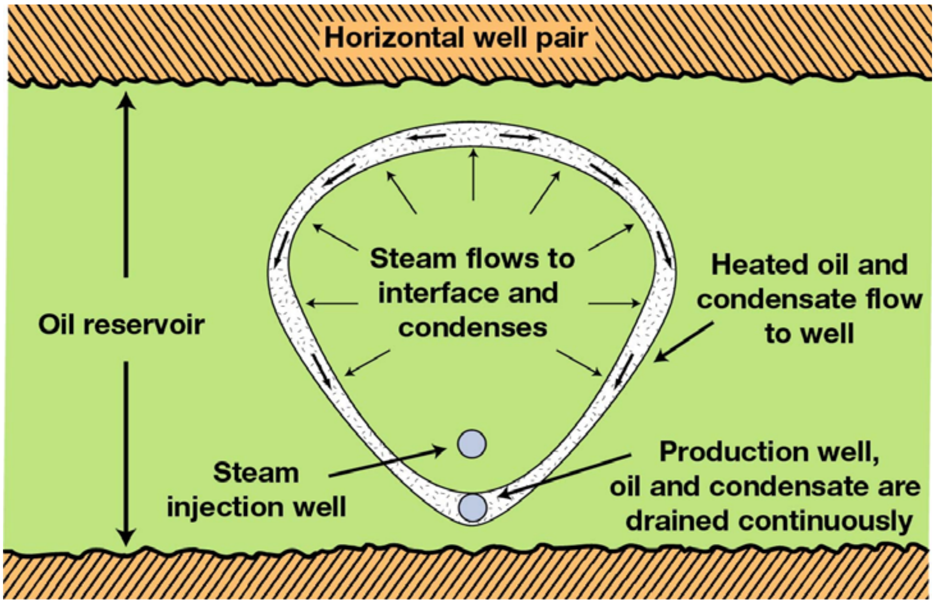
- **Up to 50% recovery can be achieved with a oil/steam ratio (OSR) of 0.2**

- **Examples: Maracaibo (Venezuela), California (Kern River), Indonesia (Duri), Alberta (Peace River)**

- **Often used after initial CSS phase (to stimulate well neighbourhoods)**

Steam Assisted Gravity Drainage

- **In the SAGD process, two parallel horizontal oil wells are drilled in the formation, one about 4 to 6 m above the other. The upper well injects steam, possibly mixed with solvents, and the lower one collects the heated crude oil that flows out of the formation, along with water from the condensation of injected steam**



Steam injection

Heat losses

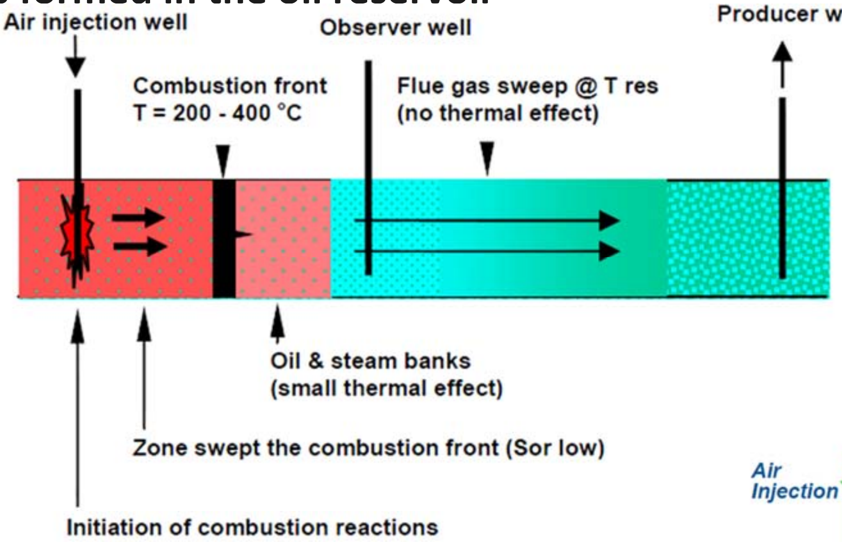
- **Heat is carried over some distance by the displacing fluid to its final destination in the reservoir**
- **Heat loss is a critical factor for recovery processes by hot fluid injection**
  - Heat loss from the reservoir to the surrounding formations: the extent of the steam condensation zone is reduced and so is the thermal efficiency of the process
  - The consequence is that it is not applicable to very thin beds or to reservoirs with a large spacing between the injector and the producer
  - Heat loss from the well: a further cause of heat loss occurs in the passage of the hot fluids in the injection well from surface to the injection zone.
- **It should be mentioned that steam generation is intensive in terms of**
  - Energy consumption and combustion of hydrocarbons
  - Environmental impact due to CO_2 produced in the above combustion
  - Use of fresh water, which can be scarce, treatment and re-cycling of produced water
- **The rewards are that the steam injection can yield high recovery factors**

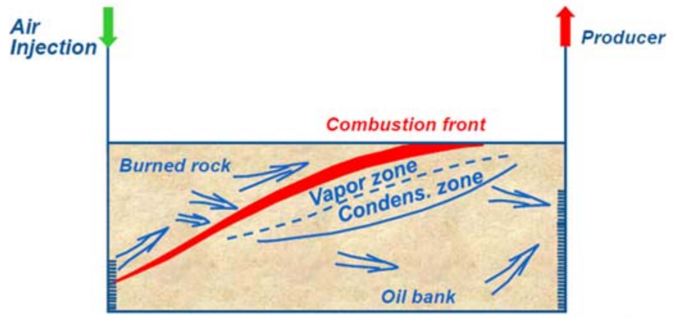
In-situ combustion

- **Oil is ignited around well bore**
- **Burning front sustained by continuous injection of air**
- **A small portion of the oil is burned**
- **The heat generated**
  - Reduces oil viscosity
  - Produces miscible fluids
  - Increases sweep efficiency
  - Reduces oil saturation
- **Continuous air injection develops efficient gas drive mechanisms**

In-situ combustion: air injection

- Schematic representation of in-situ combustion process and the various zones as formed in the oil reservoir





Continuous steam injection

Performance prediction

- Myhill and Stegemeier's Method
- The performance is presented by steam oil ratio SOR (normally between 2 to 8)
- SOR : V_s/N_p

$$V_s = \frac{Q_i}{5.61\,\rho_w (C_w \Delta T + x\,L_v)}$$

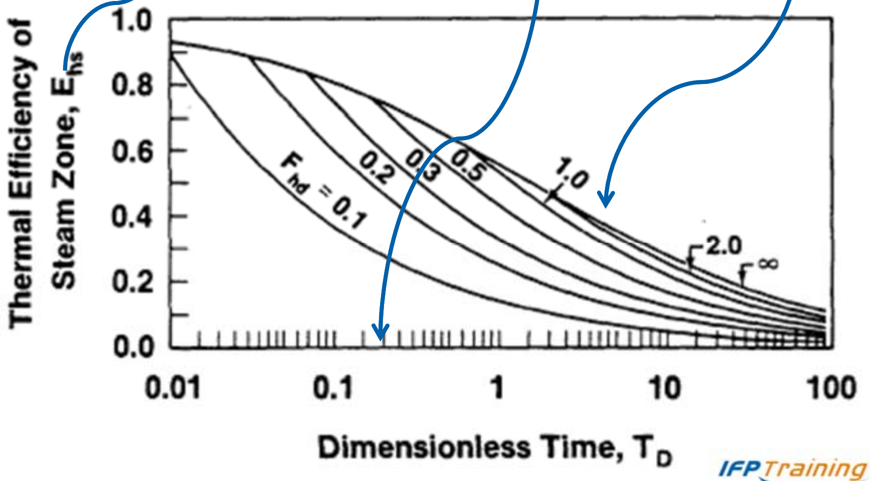
bbls, CWE

$$Q_i = \frac{A_s h_t M_s \Delta T}{E_{hs}}$$

$$T_D = \frac{4 k_R M_R t}{h_t^2 M_s^2}$$

$$F_{hD} = \frac{x L_v}{C_w \Delta T}$$

$$N_p = A_s h_n\, \phi\, \Delta S / 5.61,\ bbls$$



Nomenclature

- A_S = steam zone area [ft_2]
- h_n = net sand thickness [ft]
- f = average porosity of sand [fraction]
- ΔS = average change in oil saturation during steamflood [fraction]
- x = downhole steam quality
- L_v = latent heat of vaporization at downhole conditions [BTU/lbm]
- h_t = gross sand thickness [ft]
- M_S = average heat capacity of steam zone [BTU/ft3-°F]
- $\Delta T = T_S - T_R$ [°F]
- T_S = steam zone temperature [°F]
- T_R = original formation temperature [°F]
- E_{hs} = thermal efficiency of steam zone
- M_R = average heat capacity of cap and base rock [BTU/ft3-°F]
- t = time of steam injection [hr]
- k_R = thermal conductivity of cap and base rock [BTU/ft-hr-°F]
- Cw: Specific heat of water over the temperature range corresponding to ΔT

Key points to keep in mind

Thermal processes

- **The main objective of thermal processes is to decrease oil viscosity in order to increase oil mobility**
- **Mandatory in some cases, especially with heavy oils that may not flood in local normal conditions (typically in Canada)**
- **Drive mechanisms:**
  - Oil viscosity reduction
  - Thermal Expansion
  - Distillation
  - Solution gas drive
  - Emulsion drive

Key points to keep in mind

Thermal processes

- **Several processes may be used**
  - Cyclic steam injection
  - Steam flooding
  - SAGD
  - In-situ combustion
- **Main drawbacks of thermal processes: economics**
  - Heat losses
  - Energy to produce steam
  - Water: treatment, recycling

Notes

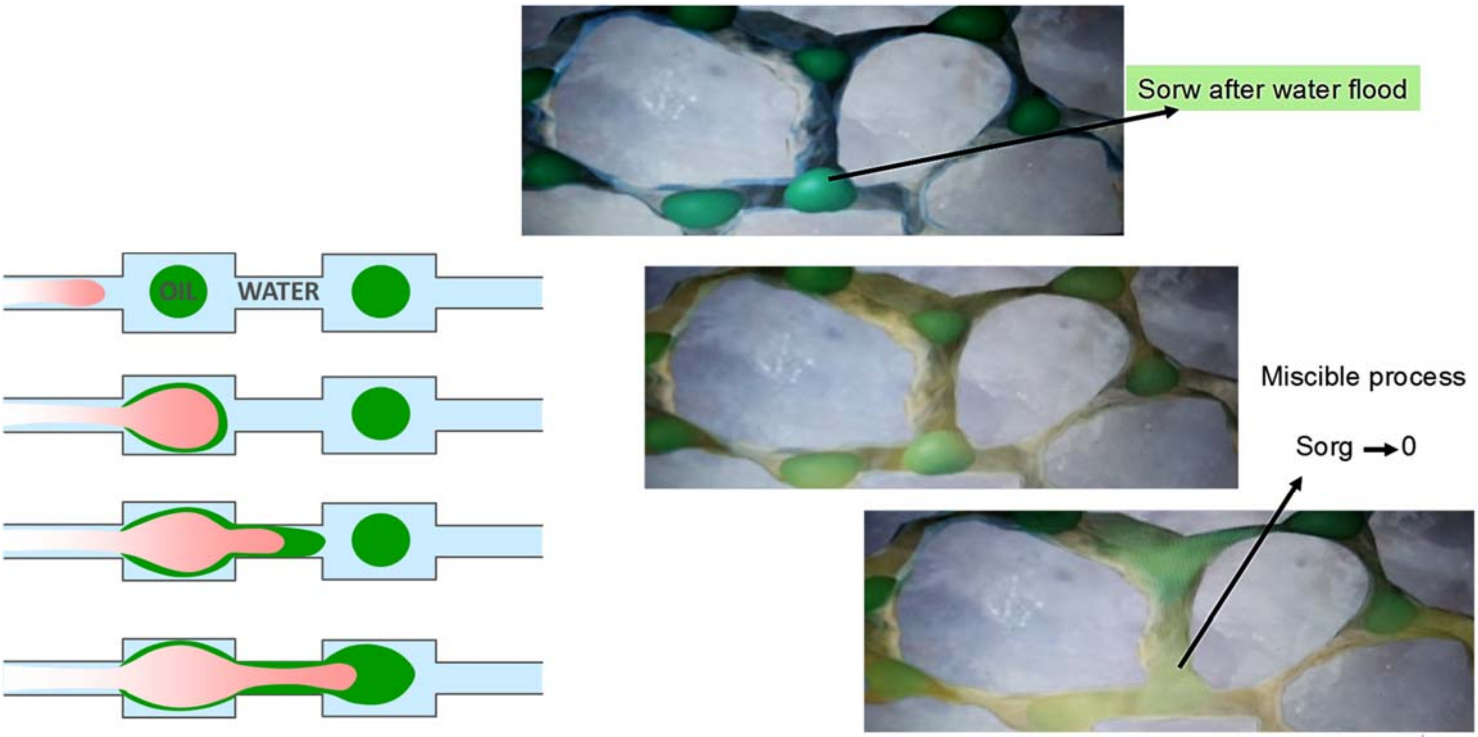
4. Miscible gas injection

Generalities

- **Definition**
  - Two fluids are miscible if they can mix in all proportions and form a single homogeneous phase
  - The minimum miscibility pressure is the lowest pressure at which miscibility (direct or multiple contact) can be achieved, at given temperature and composition
- **Miscible gas injection**
  - No more interfacial tension: S_{org} tends to zero
  - Direct (first contact) miscibility: rare
  - Multiple contact (dynamic) miscibility
    - Vaporizing gas drive
    - Condensing gas drive
- **Water Alternating Gas**
  - To improve miscible gas flooding stability

Principles of the miscible gas injection

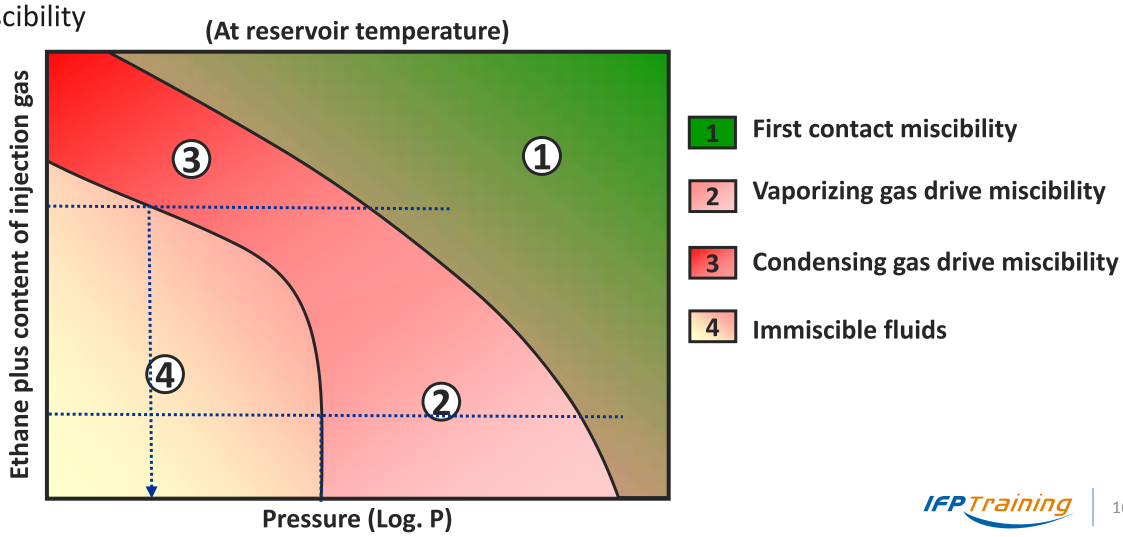
- **Pore-level mechanism: microscopic efficiency**
  - Mobilization of oil that was trapped behind water front: **oil swelling**
  - Formation of gas-oil interfaces → **reduction of IFT → S_{org} tends to zero**



Miscible gas injection

Gas-Oil miscibility

- **The miscibility depends on pressure and temperature**
- **The miscibility is rarely obtained directly: multiple-contact miscibility (also called dynamic miscibility)**
- **Multiple-contact miscibility: the injected gas and the in-situ oil exchange components until miscibility between the two phases is reached**
- **Two-types of multiple-contact miscibility:**
  - Vaporizing gas miscibility
  - Condensing gas miscibility



Gas Injection

ADVANTAGES

- **Good microscopic recovery:**
  - Low residual oil Saturation
  - Low interfacial tension
- **Good volumetric efficiency if:**
  - Gravity stable displacement
  - Miscible displacement
  - Mobility control (WAG)
- **Phase behavior**
  - Low viscosity
  - High relative permeability
  - Then high injectivity
- **Thermodynamic exchanges**
  - Oil swelling
  - First contact miscibility
  - Multi contact miscibility

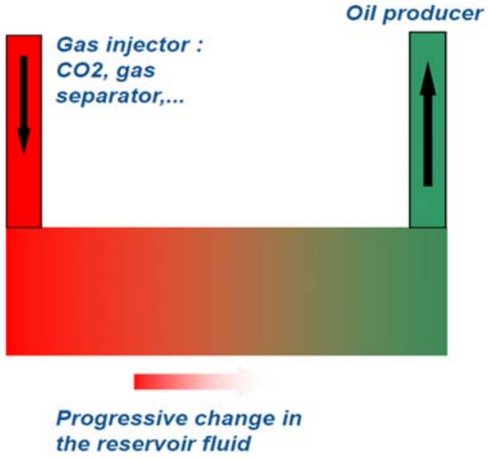
DRAWBACKS

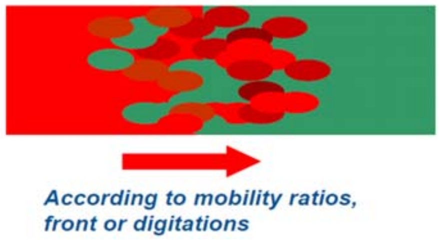
- **Reservoir Heterogeneity**
  - High sensitivity to gas sweep
- **Unfavorable mobility ratio**
  - Unstable displacement
  - Poor sweep efficiency
- **High compression cost**
- **Gas availability**

Gas Injection: first screening

- **Nature of gases:**
  - Hydrocarbon (Lean, Rich, Enriched)
  - Non Hydrocarbon: CO_2, N_2, Air, Flue Gas
- **Nature of the gas / rock / fluids reactions:**
  - Exchanges (mass transfer) = Important or not
  - Thermal effects or not (O_2 presence)
- **Thermodynamic conditions during gas oil displacement**
  - Immiscible
  - Oil Swelling
  - Partial miscible: vaporizing gas drive or condensing gas drive
  - Totally miscible at first contact
- **Conditions : secondary or tertiary conditions**

Gas injection: main mechanisms





- **According to gas and oil composition and also reservoir pressure and temperature:**
  1. Miscibility is possible: single fluid obtained
  2. No miscibility – two phases: sweeping efficiency depends on mobility ratio.

Miscibility and Miscible Floods

For a given temperature, miscibility depends on the fluid composition and the pressure:

- one hydrocarbon phase → the injection process is miscible
- two separate oil and gas phases → the injection process is immiscible

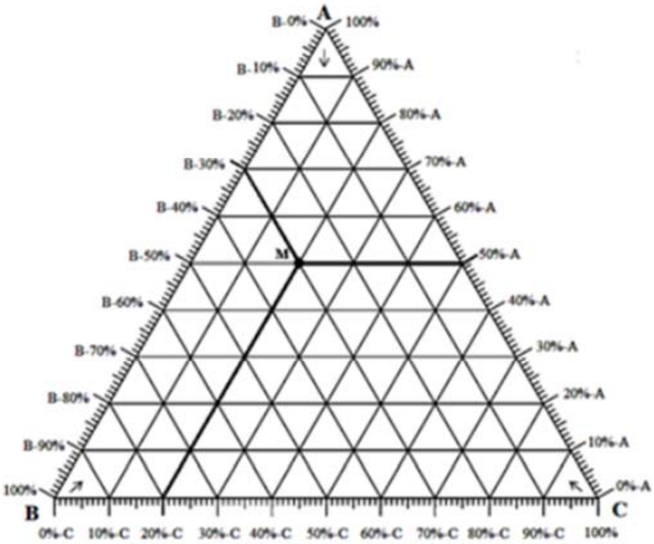
In a reservoir with a GOC, there is an interface between the gas phase and the oil phase. This interface is associated to interfacial tension (IFT). As the IFT reduces to zero, the interface disappears and the two fluids become one: we have miscibility.

The main advantage of miscibility is that there is no residual oil to gas displacement. Achieving miscibility means increasing recovery.

Miscible gas injection

Some definitions: the ternary diagram

Ternary or triangular phase diagrams can be used to plot the phase behavior of systems consisting of three components by outlining the composition regions on the plot where different phases exist.

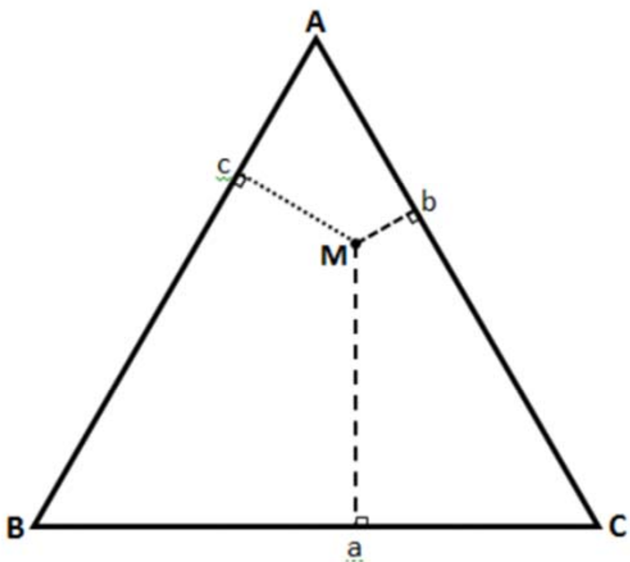


Component	Weight% in mixtur (M)
A	50
B	30
C	20

Miscible gas injection

Some definitions: the ternary diagram

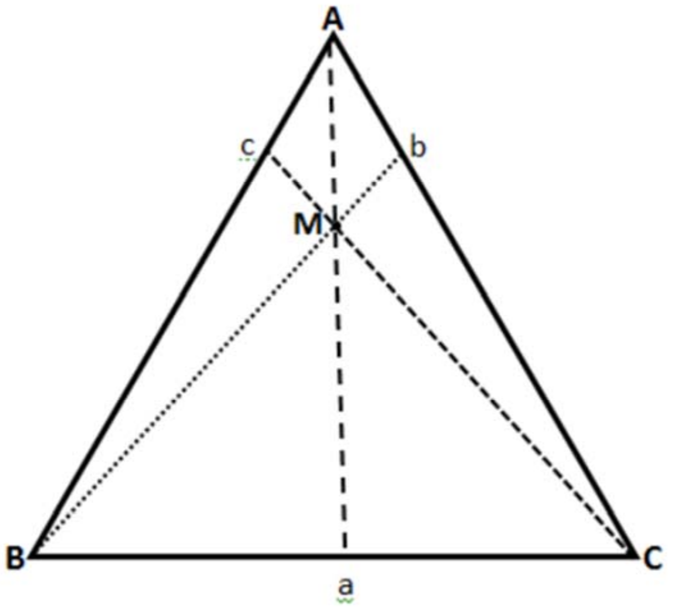
The advantage of using a ternary plot to depict compositions is that three variables can be conveniently plotted in a two-dimensional graph, and the mixture of different components can be easily represented. A ternary diagram for the hypothetical components A, B and C is:



Component	Weight% in mixture (M)
A	$\frac{\overline{Ma}}{\overline{Ma}+\overline{Mb}+\overline{Mc}}$
B	$\frac{\overline{Mb}}{\overline{Ma}+\overline{Mb}+\overline{Mc}}$
C	$\frac{\overline{Mc}}{\overline{Ma}+\overline{Mb}+\overline{Mc}}$

Miscible gas injection

Some definitions: the ternary diagram

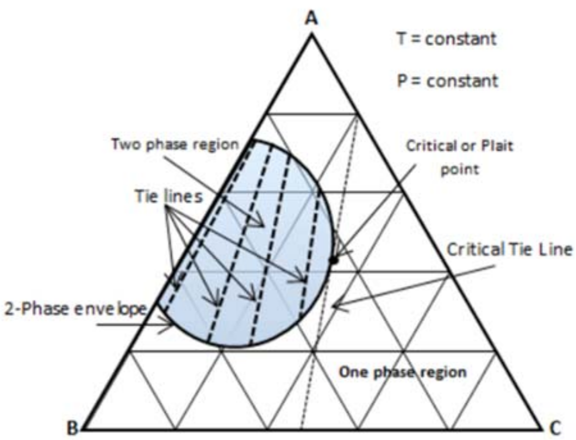


Component	Weight% in mixture(M)
A	$\frac{\overline{Ma}}{\overline{Aa}}$
B	$\frac{\overline{Mb}}{\overline{Bb}}$
C	$\frac{\overline{Mc}}{\overline{Cc}}$

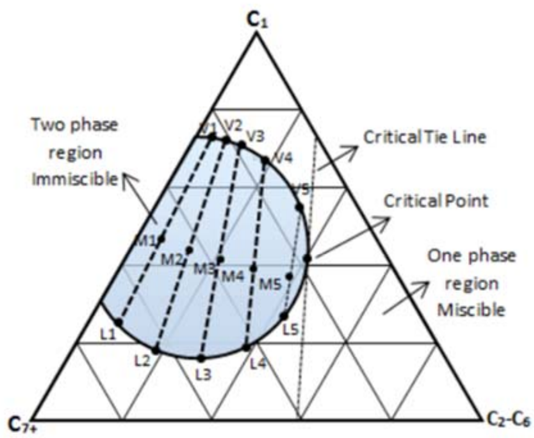
Miscible gas injection

Some definitions: the ternary diagram

Within the two-phase region there are tie lines whose ends represent the composition of equilibrium phases. The length of the tie lines shrinks toward the critical (plait) point where the properties of two phases are indistinguishable. The position of the plait point changes with temperature at a fixed pressure. Any composition represented by points (M1-M5) inside the two-phase envelop would separate into two phases (V1-V5 as vapor and L1-L5 as liquid), the relative amount of two phases can be calculated by using inverse-lever-arm rule. The points outside the two-phase envelop are representative of a single phase composition. The critical tie line is the fictitious tie line tangent to the bimodal curve at the critical point. The critical tie line is the limiting case of the actual tie line as the plait point is approached.



(a). ternary phase diagram for a system of components A, B, C with limited miscibility

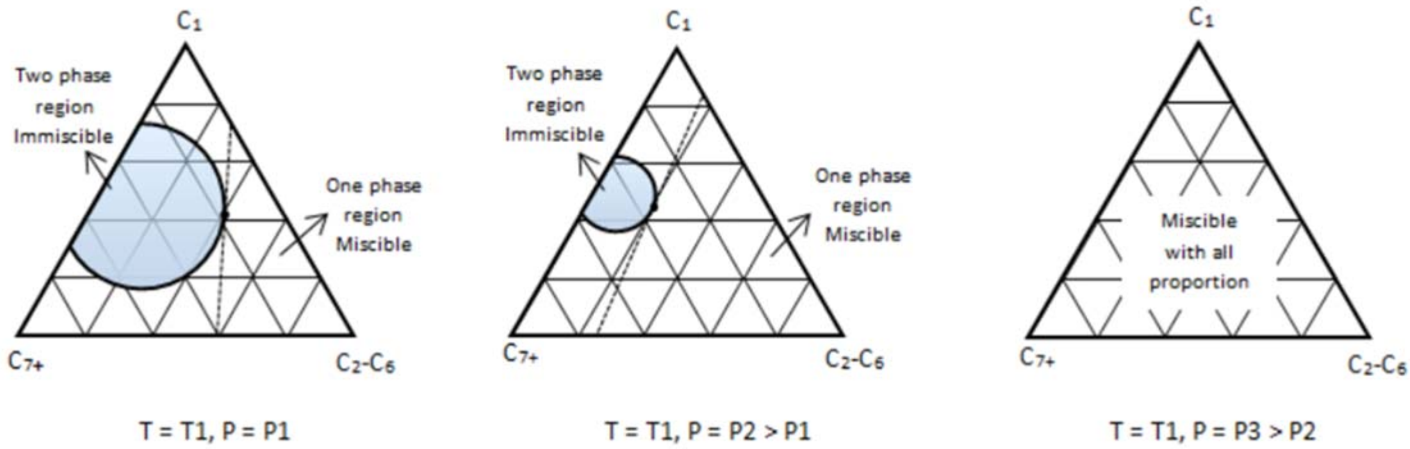


(b). Pseudoternary diagram

Miscible gas injection

Some definitions: the ternary diagram

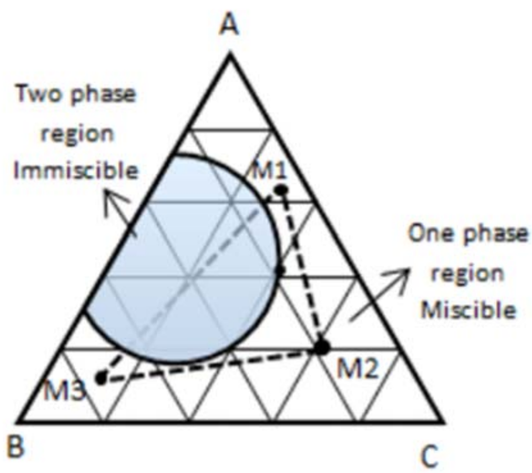
As the pressure increases, the two-phase region shrinks, or in other words light-heavy miscibility increases. No general statement is possible about the effect of temperature though the two-phase region generally grows with the increasing temperature.



Miscible gas injection

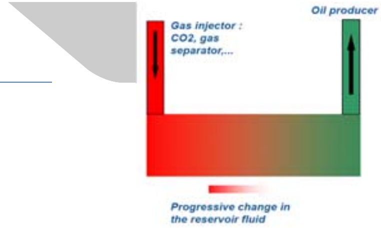
Some definitions: the ternary diagram

In ternary diagram the mixture results of any combination of two components will lie on a straight line connecting two components to each other. According to this, any combination of components A and C, and any combination of B and C, form a single phase, in other words in this specific pressure and temperature, A and C, B and C are miscible. A and B are not miscible because the straight line between them pass through the two-phase region, so mixing them with special compositions will end in a two phase mixture. And with the same manner M1 and M2 are miscible the same as M2 and M3. But M3 and M1 are not miscible, because the straight line between them passes through the two-phase region

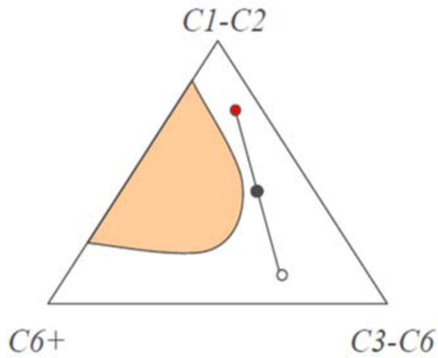


Miscible gas injection

Compositional effects (miscibility)

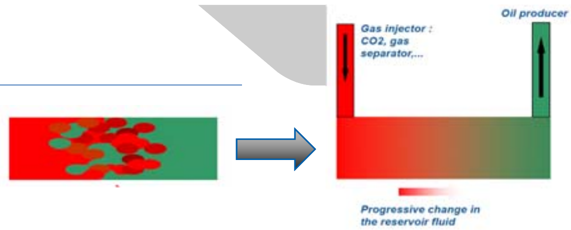


- **Fluid characteristics**
  - Fluid in place: volatile oil (rich in C3-C6)
  - Injected fluid: rich gas (rich in C3-C6)
- **Compositional effect**
  - Bilateral exchange of components
  - No more interface between gas and oil; no interfacial tension
- **Consequences**
  - The mixture gives a single fluid
  - No more Kr and Pc
  - Improvement of the microscopic recovery.

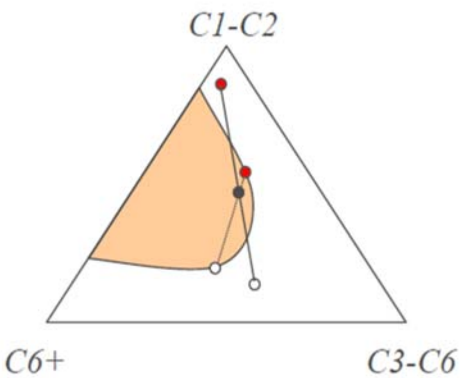


Miscible gas injection

Compositional effects (oil stripping)

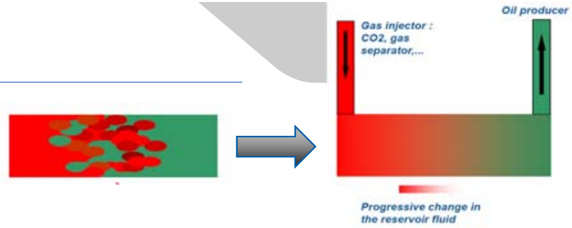


- **Fluid characteristics**
  - Fluid in place: volatile oil (rich in C3-C6)
  - Injected fluid: dry gas (poor in C3-C6)
- **Compositional effect**
  - Intermediate components (C3-C6) pass from the oil into the gas
- **Consequences**
  - Possibility to recover intermediate components with gas cycling.

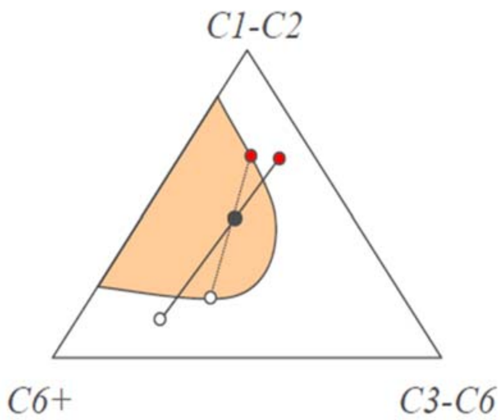


Miscible gas injection

Compositional effects (oil swelling)

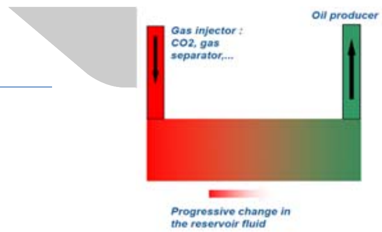


- **Fluid Characteristics**
  - Fluid in place: medium/heavy oil (poor in C3-C6)
  - Injected fluid: rich gas (rich in C3-C6)
- **Compositional effect**
  - Intermediate components (C3-C6) pass from the gas into the oil
- **Consequences**
  - Decrease oil viscosity and density
  - Enhancement of W/O mobility ratio

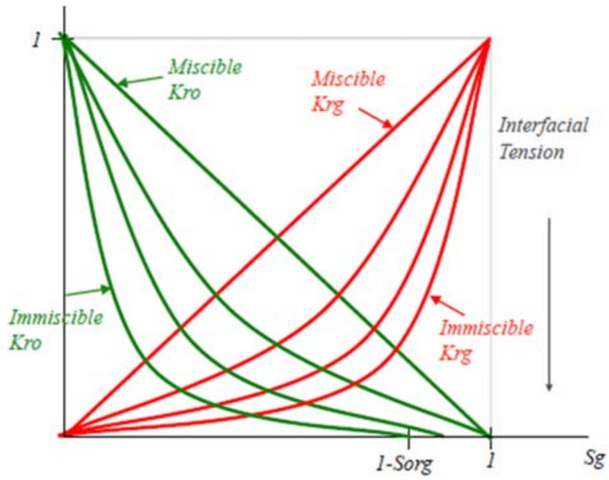


Miscible gas injection

Relative permeabilities

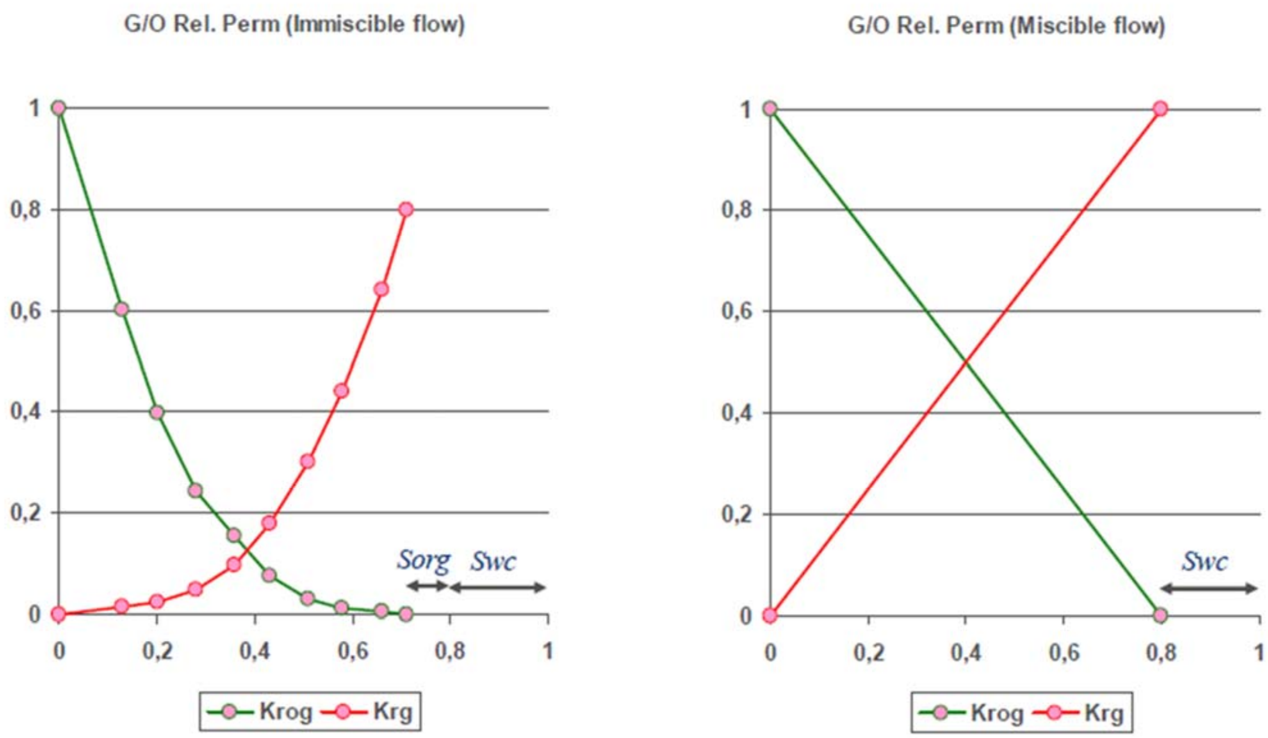


- **Characteristics**
  - Bilateral exchange of components
  - No more interface between gas and oil
  - No interfacial tension (IFT = 0)
- **Consequences**
  - The mixture gives a single fluid
  - No more relative permeability and capillary pressure in the G/O system
- **Improvement of the microscopic recovery**



Miscible gas injection

Relative permeabilities



Sorg = 0 and high oil & gas mobility when flow is miscible

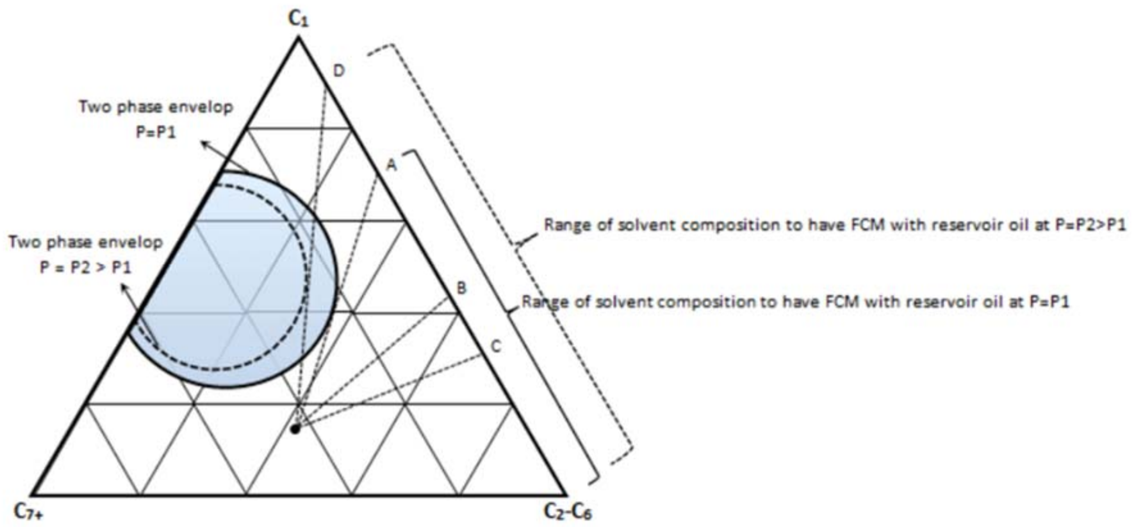
How do we get miscibility?

There is a minimum pressure required to achieve miscibility, and this pressure depends on the process. There are two main miscible processes:

- **First-contact miscibility**
- **Multi-contact miscibility**
  - Condensing drive
  - Vaporizing drive

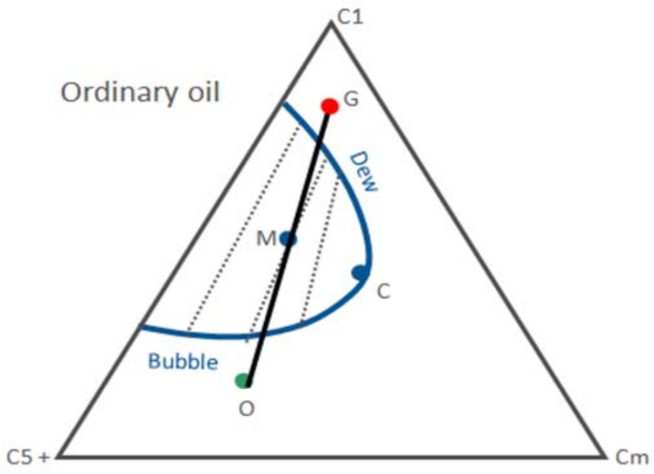
First-contact miscibility

- In theory, first-contact miscibility can be achieved with most gases, but it crucially depends on the pressure being high enough.
- The first contact miscibility pressure at which any mixture of the original reservoir oil and injection gas is single phase.
- Pressures are generally too low for first-contact miscibility.

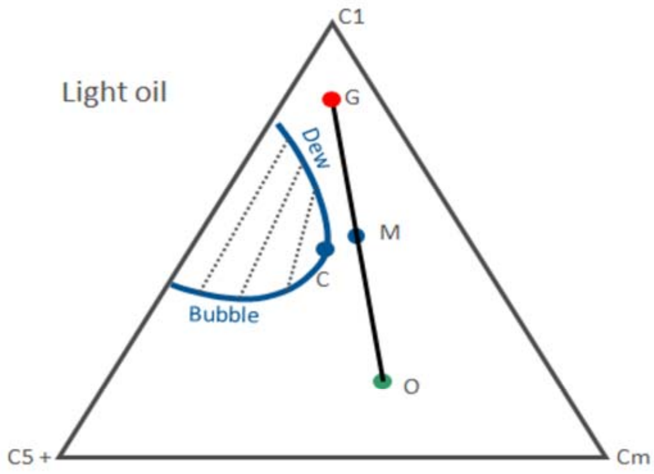


First-contact miscibility

Composition effect



Immiscible Gas oil system

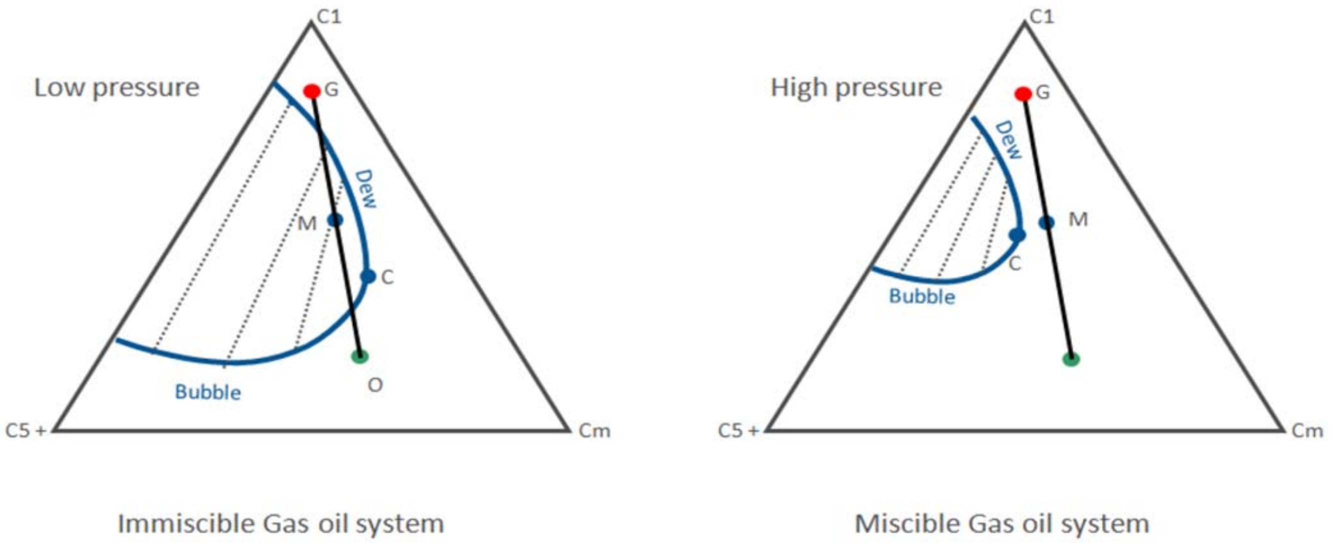


Miscible Gas oil system

Light oil is favorable to miscible gas injection

First-contact miscibility

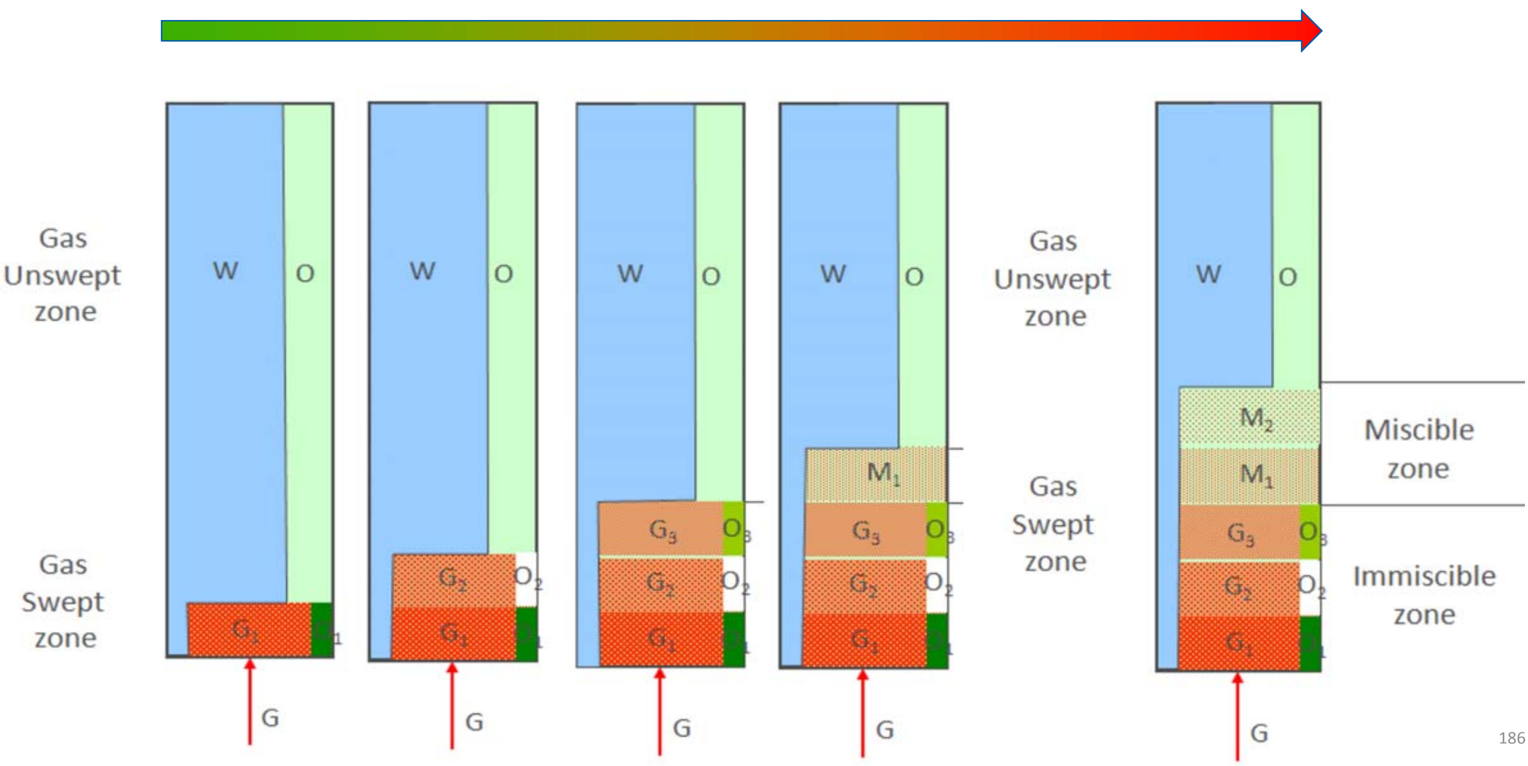
Pressure effect



High pressure is favorable to miscible gas injection

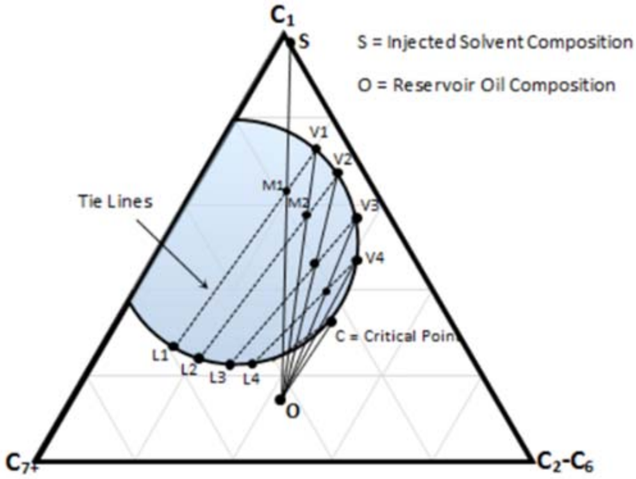
Multi-contact miscibility

For reservoirs with an initial pressure below the FCMP, we can look for an alternative process that can also give us miscibility at a Multi-contact miscibility pressure.



Vaporizing gas drive miscibility

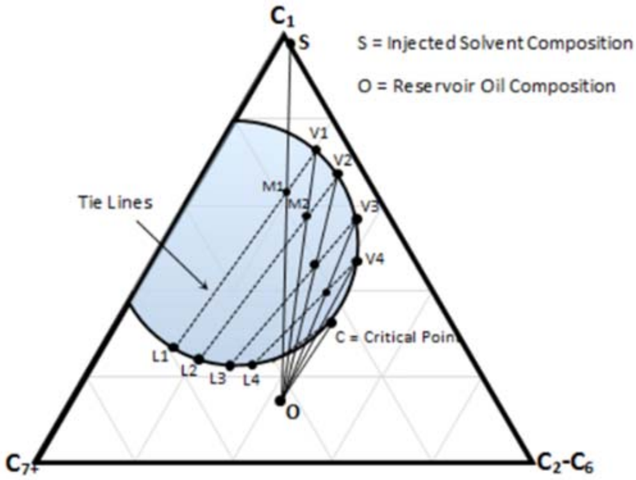
The injected gas ‘S’ after contacting the oil ‘O’ forms a mixture ‘M1’ that is split into two equilibrated phases of liquid L1 and gas V1, determined by the equilibrium tie line. It should be mentioned that the gas phase, V1, is the original solvent gas, S, after it has been enriched with some intermediate and heavy fractions from the oil phase. The gas V1 will have much higher mobility than L1 and moves forward and makes further contact with fresh oil to form mixture M2. The mixture M2 splits into gas V2 and liquid L2. The gas V2 is richer particularly in the intermediates. For the next time V2 passes L2 because of higher mobility and contacts to the fresh oil to form mixture M3 that is split into L3 and V3, and so far.



Vaporizing gas drive miscibility

After some steps the gas phase will no longer form two phases when in contact with fresh oil. In other words the dilution straight line between ‘O’ and the gas phase does not pass through the two-phase region and the gas becomes miscible with oil at point ‘C’, that is, where the tangent line at the critical point, which is the critical tie line with zero length, goes through the oil composition ‘O’.

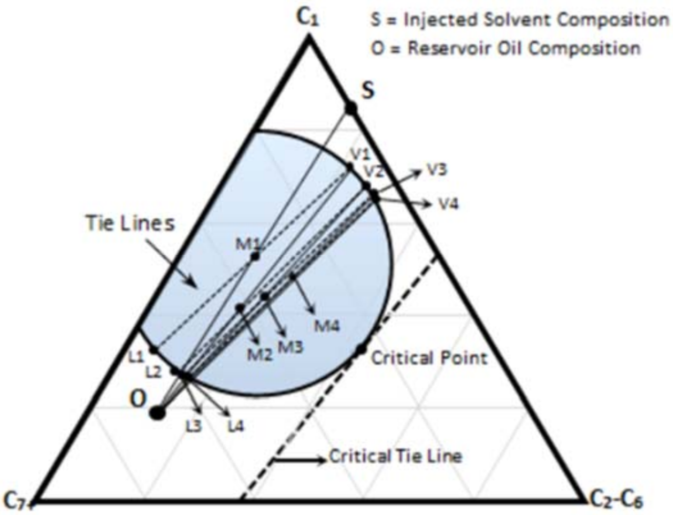
In the vaporizing gas drive there is a transition zone; the miscibility is achieved at the front of the advancing gas; the gas composition varies gradually from that of the injected gas till reaching the ‘critical point composition’. Then its miscibility displaces the original reservoir oil in a piston-type manner. No phase boundary exists within the transition zone.



Vaporizing gas drive miscibility

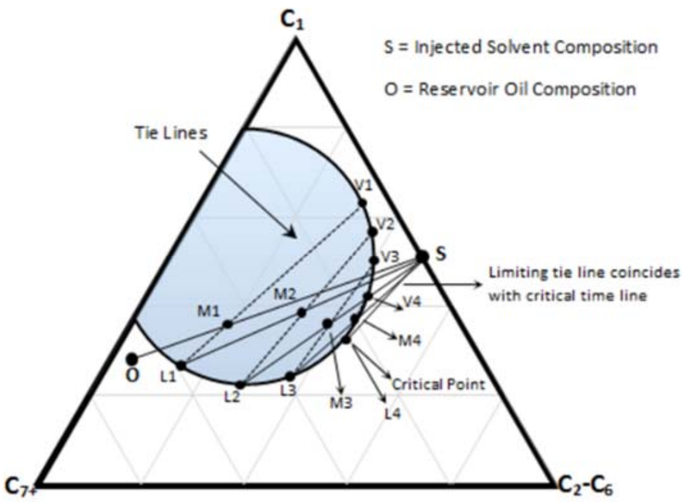
Immiscible displacement

The injection gas 'S' does not achieve multiple contact miscibility with oil 'O'. The initial mixture 'M1' is the first mixture after the contact of the gas 'S' and oil 'O'. The mixture is split into the gas V1 and the liquid L1. The gas phase will flow forward to form the mixture M2, and so forth. This gas is being enriched in intermediate components at the leading edge of the solvent-oil mixing zone as discussed before. But enrichment cannot proceed beyond the gas-phase composition given by the tie line whose extension passes through the oil 'O' which is called Limiting tie line. In other words, enrichment of the advancing gas is limited by the tie line (V4-L4 here) which, if extended, goes through oil 'O'.



Condensing gas drive miscibility

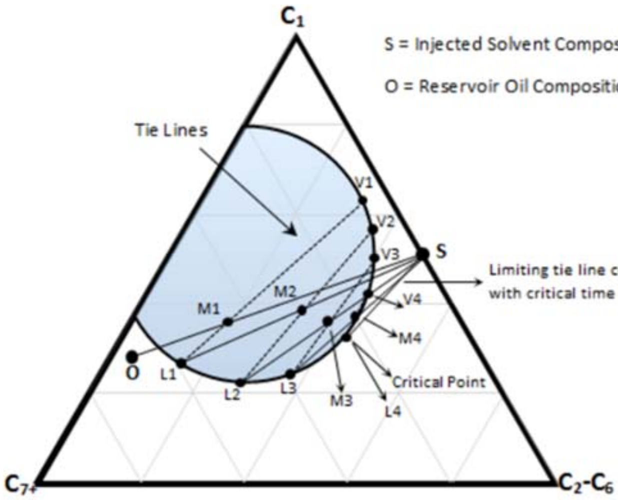
Oil 'O' and injected fluid 'S' are not miscible initially as the dilution straight line between them passes through the two-phase region. M1 is the first mixture resulting after first contact of 'S' and 'O'. M1 will split into the liquid L1 and gas V1 that are in equilibrium at this point in the reservoir. The liquid phase L1 is richer in intermediate components than the original oil 'O'. The gas phase V1 moves faster because of its higher mobility and leaves the oil phase L1 to mix with the fresh fluid injected 'S' to form the mixture M2. The new mixture will split into liquid L2 and gas V2. The liquid L2 lies closer to the critical (plait) point than L1 and it is richer in intermediate components. The gas passes the liquid phase and L2 contact with the fresh solvent to form M3 and so forth.



Condensing gas drive miscibility

By continuing the injection of the solvent 'S' the composition of the liquid phase is altered progressively in a similar manner along the bubble point curve until it reached the critical point.

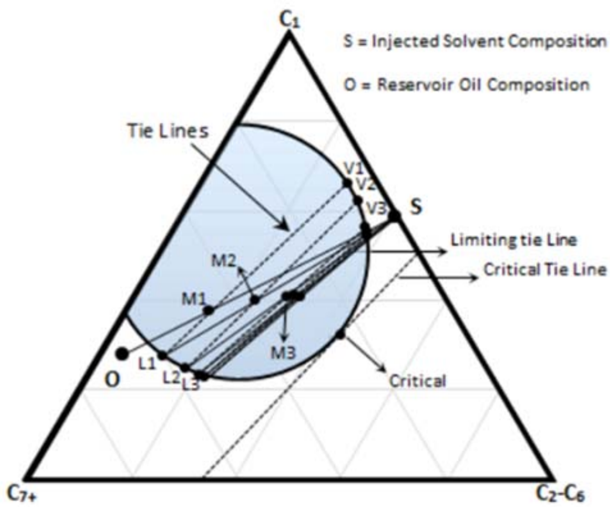
The plait point fluid is directly miscible with the injection fluid 'S'. The limiting tie line in this process passes through the solvent composition 'S', so the MMP in this process is defined as the pressure at which the critical tie line coincides with the limiting tie line and its extension passes through the solvent composition



Condensing gas drive

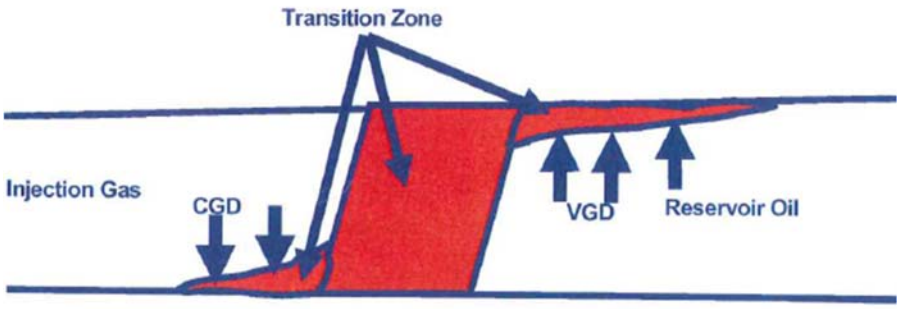
Immiscible displacement

To achieve dynamic miscibility with the condensing-gas drive method with an oil whose composition lies to the left of the critical tie line, the enriched gas composition must lie to the right of the critical tie line. If a gas injected contains less intermediate hydrocarbon so that both oil and solvent compositions located on the two-phase side of the critical tie line the oil cannot be enriched to the point of miscibility. The enrichment of the liquid phases (L1, L2,…) continues till a point that the resulting mixture lies on the tie line that passes through the injected solvent composition point 'S'. The enrichment will stop at this point. *For this system, miscibility can be achieved by increasing pressure to shrink the phase envelop, so that the limiting tie line coincides with the critical tie line*



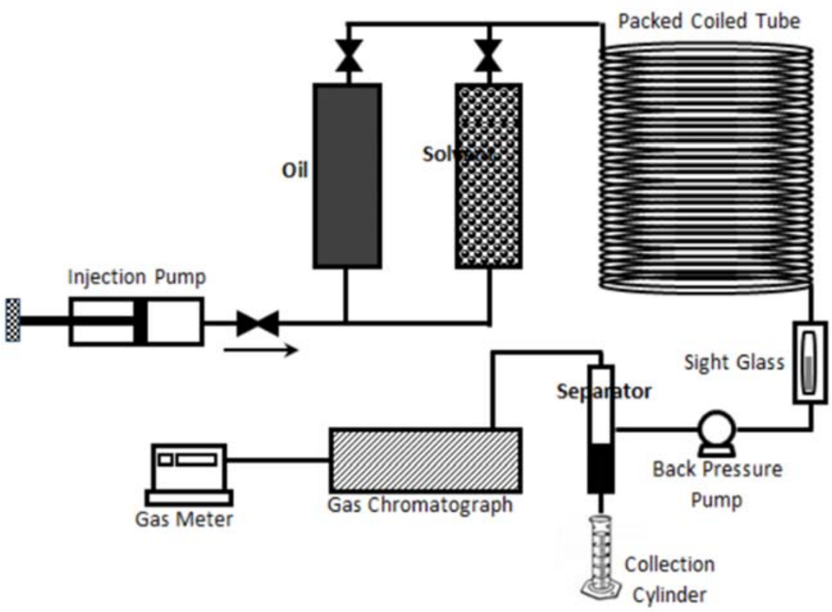
Condensing-vaporizing gas drive miscibility

- **The process that occurs in a reservoir cannot be represented as either a vaporizing or a condensing process only. Both probably take place at the same time:**
  - Injection gas enriches the oil in the light intermediate range
  - Also, it strips the heavier fractions
  - Thus, the reservoir oil in contact with fresh gas initially becomes lighter, but as it contacts more gas and looses the middle intermediates and lighter heaviers, it tends to get heavier.
  - This heavier oil becomes less miscible with the injection gas.



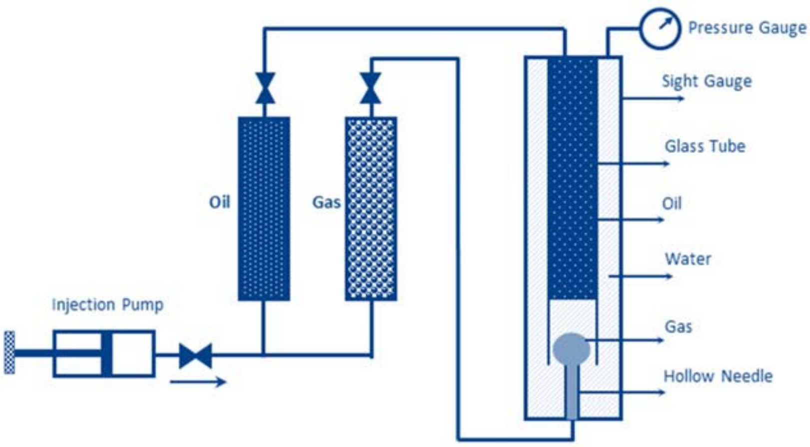
Minimum miscibility pressure (MMP): Slim tube test

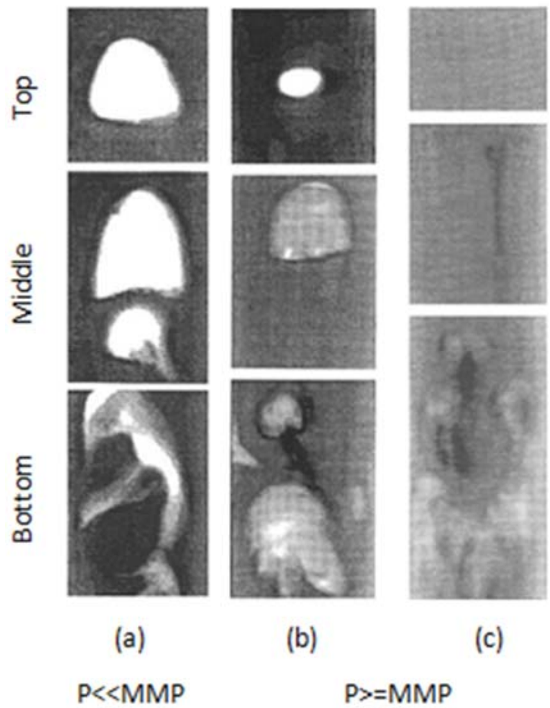
Laboratory experiments are carried out to estimate the MMP. A slim tube experiment is conducted by injecting gas of a fixed composition into oil, at a number of different pressures. The oil recovery is plotted as a function of pressure. At some pressure the injected gas is to the right of the limiting tie line and MCM develops.



Minimum miscibility pressure (MMP): RBA

- **Rising bubble apparatus (RBA)**

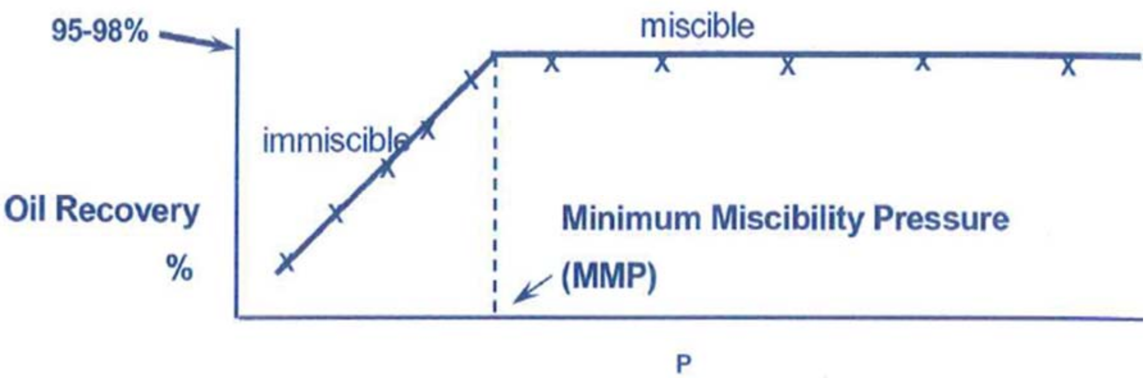




Paper SPE 13114

Minimum miscibility pressure (MMP): Slim tube test

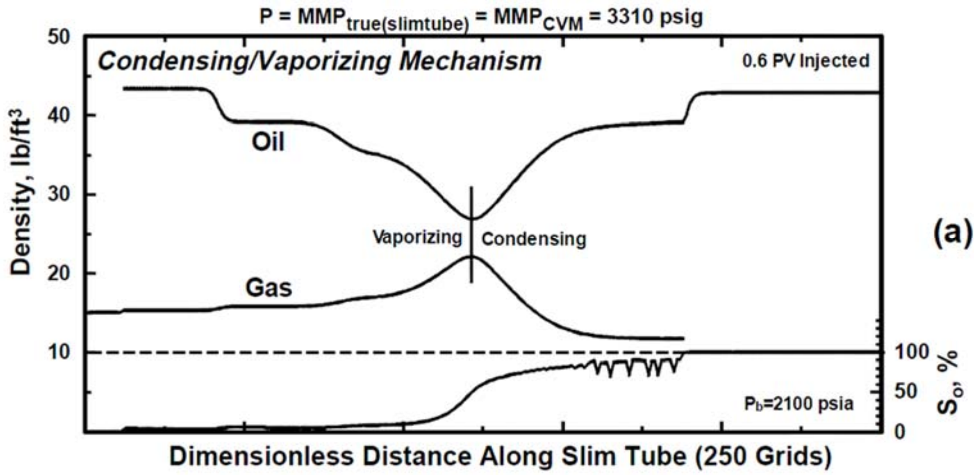
As the pressure is increased, the two-phase region becomes smaller until we reach the miscibility pressure. At that pressure the oil recovery will be maximum as the oil and gas will form a single phase throughout the slim tube, and residual oil will drop close to zero. The pressure at which the maximum recovery is first reached is the MMP.



Miscible slim tube test simulations:
at MMP for condensing vaporizing

A simple way to establish if a miscible slim tube simulation encounters a vaporizing or a mixed condensing/vaporizing mechanism can be seen from a plot of gas/oil densities and oil saturation versus distance along the slim tube (prior to breakthrough, e.g. at 0.6 PV injected).

An "hour-glass" shape on the density-distance plot indicates a mixed condensing/vaporizing mechanism, with the miscible front being located at the minimum in density difference. Furthermore, two phases are found on both sides of the front. The extent of the two-phase region ahead of the front may vary from very short (for a highly undersaturated system) to quite long for a slightly-undersaturated (or initially two-phase) system.



Vaporizing gas drive miscibility
In practice…

- **Multiple contact miscibility**
- **Lean (Separator) gas (75 to 100% C1) = continuous injection**
  - 60 to 100% HCPV (10-15 years) (Prod Gas Re-injected)
- **C2-C6 Transfered from oil (Light Oil ~ 40° API) to gas**
- **Operating pressure → 4500 psi**
- **Projects**
  - Large scale - Long period
  - Mainly secondary recovery
  - Recovery > 50% OOIP
  - Examples : Hassi Messaoud (Algeria)

Condensing gas drive miscibility

In practice…

- **Multiple contact miscibility (C2+ transferred from Gas to Oil)**
- **Enriched gasi**
- **Slug size = 10 to 20% HCPV**
- **Operating pressure = 1,500 to 3,000 psi (for 30° API)**
- **Projects**
  - Secondary projects mainly (Oil Gravity = 30 to 50° API)
  - Several CGD in Pinnacle Reefs (Canada)
  - Examples: Rainbow (Alberta), Intisar (Libya)
  - Estimated incremental recovery: + 15 to 25% OOIP

Tertiary Oil Recovery by Gas Injection

- **Gas injection to sweep oil zones unswept by water – Water Alternate Gas**

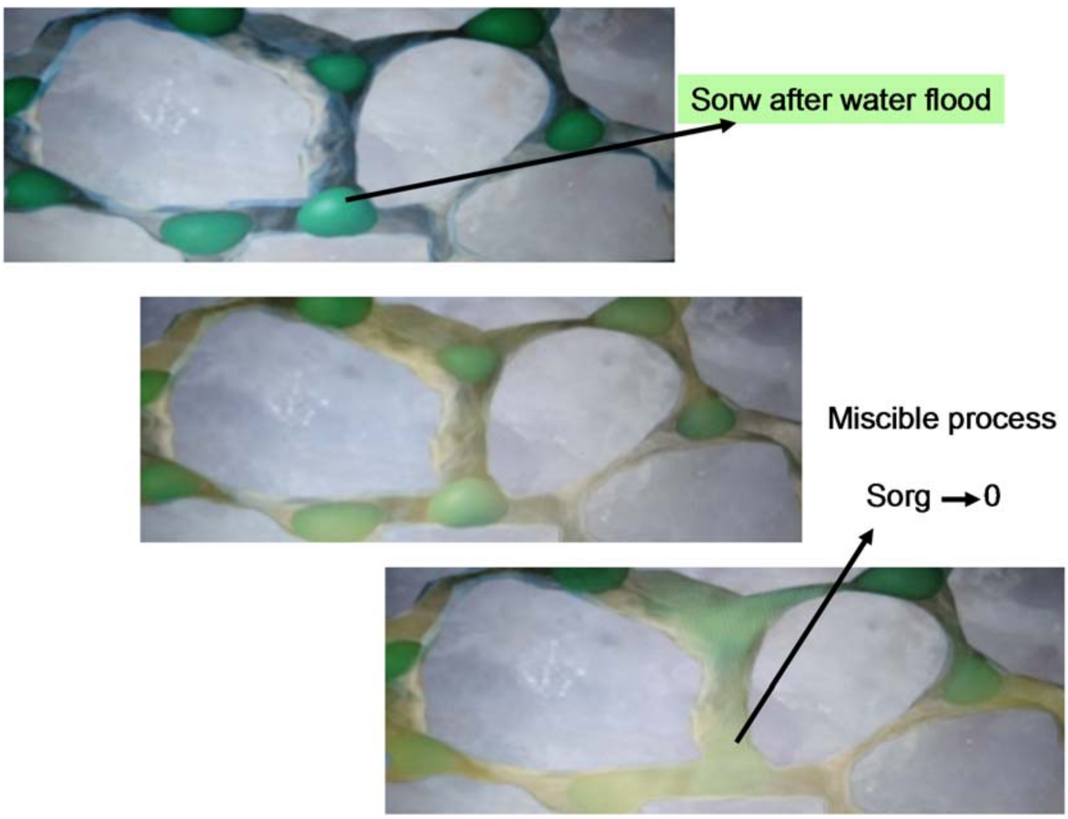
- **Gas gravity displacement**

Water alternate gas (WAG)

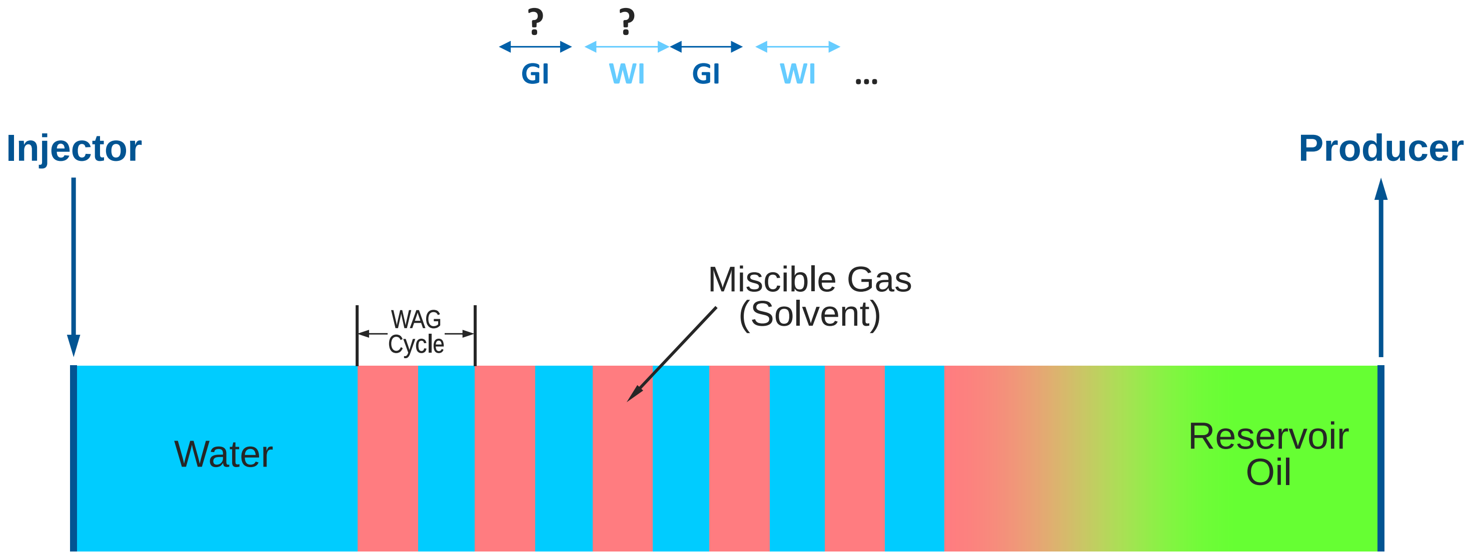
With miscible gas

- **Principles**
  - To optimize the microscopic recovery (gas-oil displacement)
  - To optimize the volumetric recovery (water-oil displacement)
- **Advantages**
  - Management of associated gas
  - Reduces gas mobility
  - Sweeps zones that are not flooded by water
  - Supposed to improve the microscopic efficiency
- **Disadvantages**
  - “Unnatural injection”
    - Risk of rapid fluid segregation
    - Strong sensitivity to heterogeneities
    - Risk of rapid gas breakthrough
  - Decrease in water injectivity

Miscible gas injection to remove Sorw after waterflood



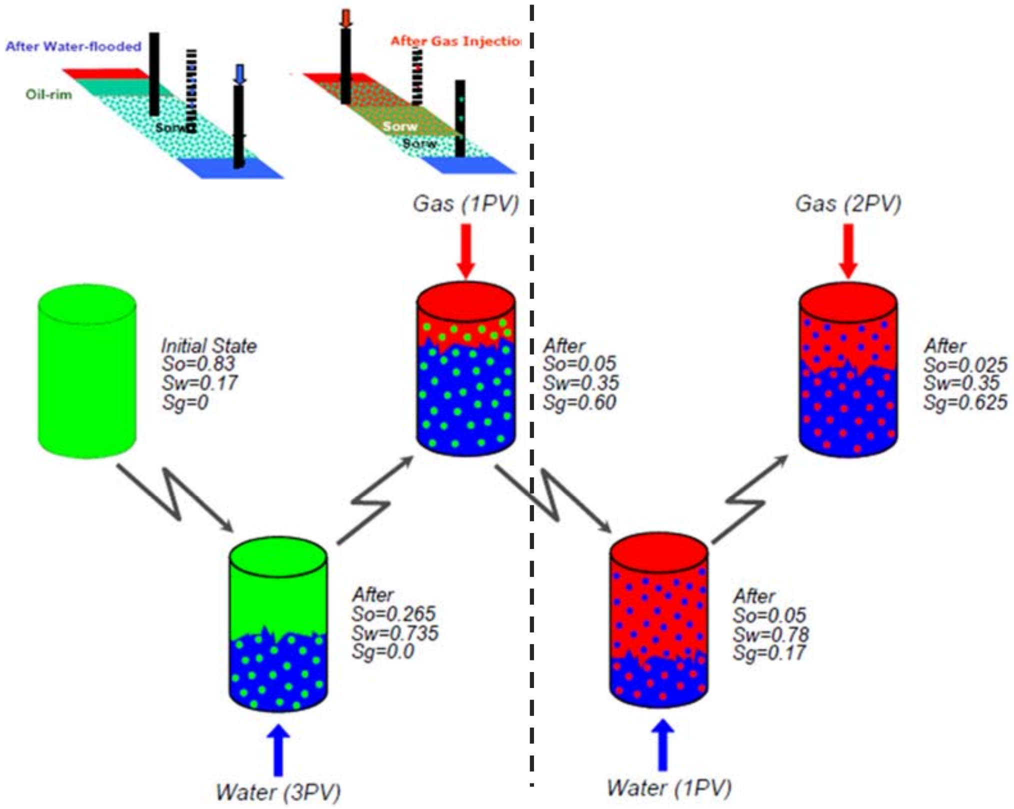
- Cycles of gas and water injection alternated (injection period variable ?)



2 WAG cycles (P > MMP)

Cycle 1

Cycle 2



Water alternate gas

Important parameters

- **Reservoir thickness**
- **Kv, permeability barriers:**
  - Works best in a stratified reservoir
- **Spacing between wells**
- **Kh anisotropy**
- **WAG ratio and size of slugs**

Gas injection after waterflood

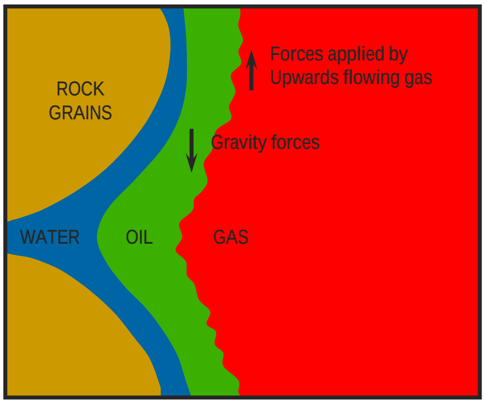
Advantages

- **Residual oil recovery can be obtained**
  - Either by immiscible displacement (which is beneficial if Sorg < Sorw)
  - Or through compositional effects (which can leave very low oil saturations by vaporization, or even fully sweep if strict miscibility is achieved).
- **Oil sweep oil in areas not been reached by water can be obtained**
  - By differences in densities
  - And possibly by new injection points.

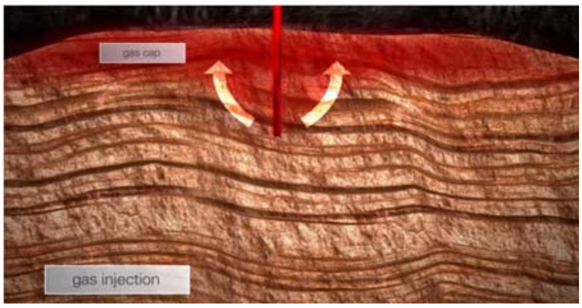
Gravity drainage effects

- When gas is injected at the crest of the structure, preferably in a gas cap, and if the dip angle is sufficient, the difference in gravity between gas and oil will promote segregation between the two fluids, this will allow the GOC to move downwards in gravity stable manner, despite the gas high mobility.

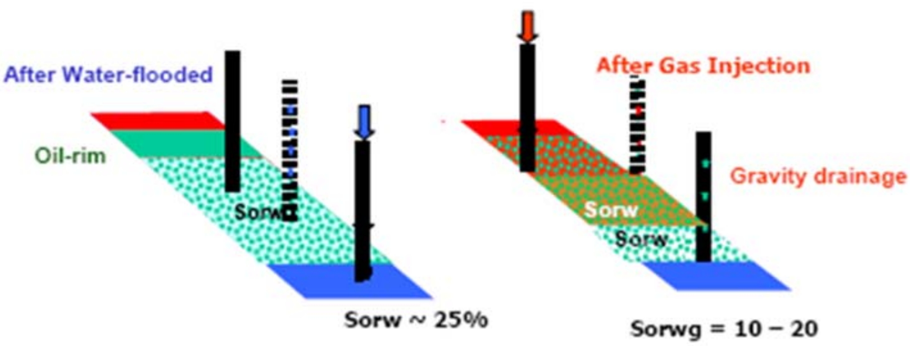
- Indeed, what happens is that the oil droplets will congregate in the presence of gas and will form a continuous phase that will keep on decanting slowly downwards to the producing wells.

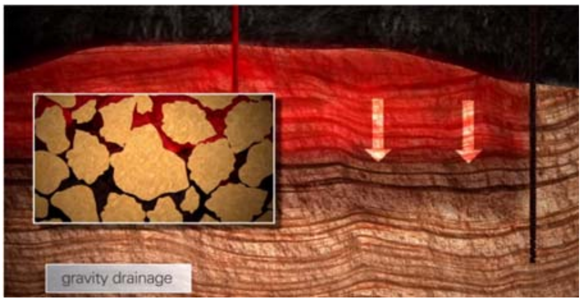


Gravity drainage effects

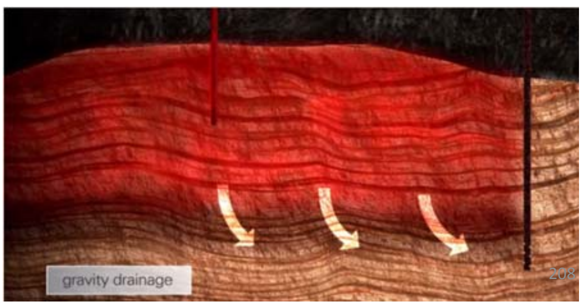


- An oil saturation of around 15-20% remains behind the gas front. This residual oil saturation will decrease with time.





- *This is the most efficient IMMISCIBLE GAS DISPLACEMENT process.*



BP Videos – YouTube
Exploiting science to increase oil recovery series

Key points to keep in mind

Miscible Gas Injection

- **Principles**
  - Two fluids are miscible if they can mix in all proportions and form a single homogeneous phase
  - No more interfacial tension: S_{org} tends to zero
- **Definitions**
  - Minimum miscibility pressure (MMP): the minimum miscibility pressure is the lowest pressure at which miscibility (direct or multiple contact) can be achieved, at given temperature and composition
  - MMP tests: Slim tube test and Rising bubble test
  - First contact miscibility: the first contact miscibility pressure at which any mixture of the original reservoir oil and injection gas is single phase.
  - Multiple contact miscibility: multiple-contact miscibility: the injected gas and the in-situ oil exchange components until miscibility between the two phases is reached

Key points to keep in mind

Miscible Gas Injection

- **Thermodynamic conditions during gas oil displacement**
  - Immiscible
  - Oil Swelling
  - Partial miscible: vaporizing gas drive or Condensing gas drive
  - Totally miscible at first contact
- **Multiple contact miscibility mechanisms**
  - Condensing miscibility: intermediate components (C3-C6) pass from the gas into the oil → the mixture gives a single fluid
  - Vaporizing miscibility: intermediate components (C3-C6) pass from the oil into the gas → the mixture gives a single fluid
  - Condensing-vaporizing: injection gas enriches the oil in the light intermediate range and strips the heavier fractions from the reservoir oil, then gas becomes heavier and oil becomes lighter → the mixture gives a single fluid

Key points to keep in mind

Miscible gas injection

- **Advantages**
  - Good microscopic recovery: low residual oil saturation and interfacial tension
  - Good volumetric efficiency if miscible displacement and gravity stable displacement
  - Phase behavior: low viscosity, high relative permeability
  - Then high injectivity
  - Thermodynamic exchanges: oil swelling and miscibility
- **Drawbacks**
  - High sensitivity to gas sweep
  - Unfavorable mobility ratio if unstable displacement → poor sweep efficiency
  - High compression cost
  - Gas availability

Key points to keep in mind

Water alternate gas

- **Principles: alternated cycles of water and miscible or immiscible gas injection**
  - To improve miscible gas flooding stability
  - To optimize the microscopic recovery (gas-oil displacement)
  - To optimize the volumetric recovery (water-oil displacement)
- **Advantages**
  - Residual oil recovery can be obtained by immiscible displacement or through compositional effects (which can leave very low oil saturations by vaporization, or even fully sweep if strict miscibility is achieved). Improves the microscopic efficiency
  - Oil Sweep oil in areas that have not been reached by water can be obtained by differences in densities and possibly by new injection points.
  - Management of associated gas
- **Drawbacks**
  - Risk of rapid fluid segregation
  - Strong sensitivity to heterogeneities
  - Risk of rapid gas breakthrough
  - Decrease in water injectivity

Key points to keep in mind

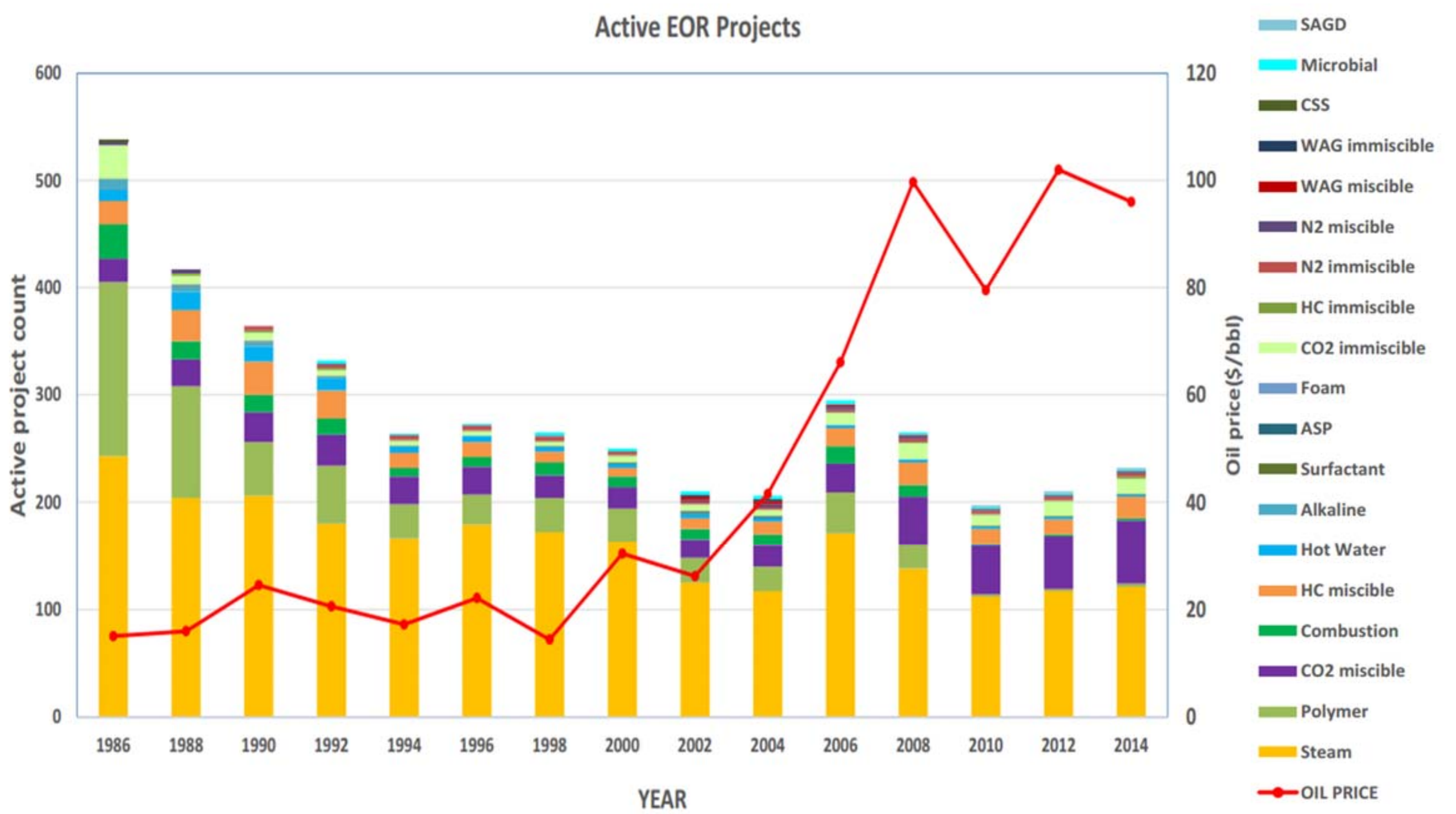
Gravity drainage

- **Immiscible gas injection**
- **When gas is injected at the crest of the structure, preferably in a gas cap, and if the dip angle is sufficient, the difference in gravity between gas and oil will promote segregation between the two fluids, this will allow the GOC to move downwards in gravity stable manner, despite the gas high mobility.**

Notes

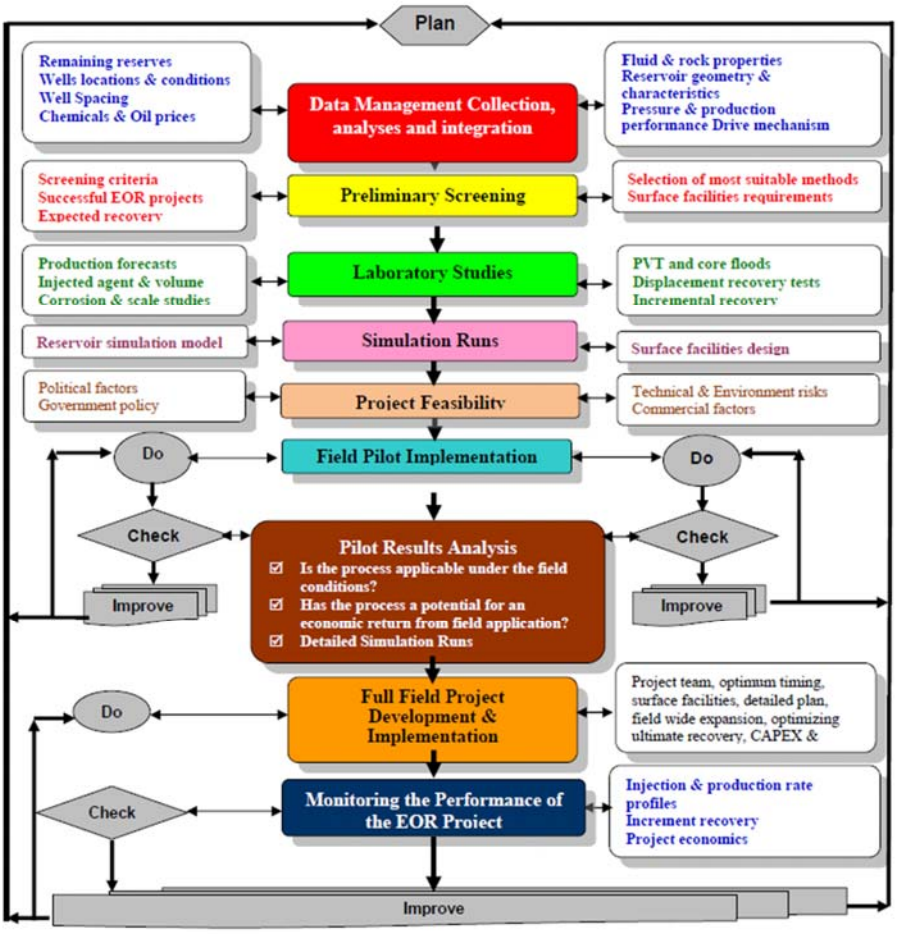
5. EOR projects implementation

EOR project history



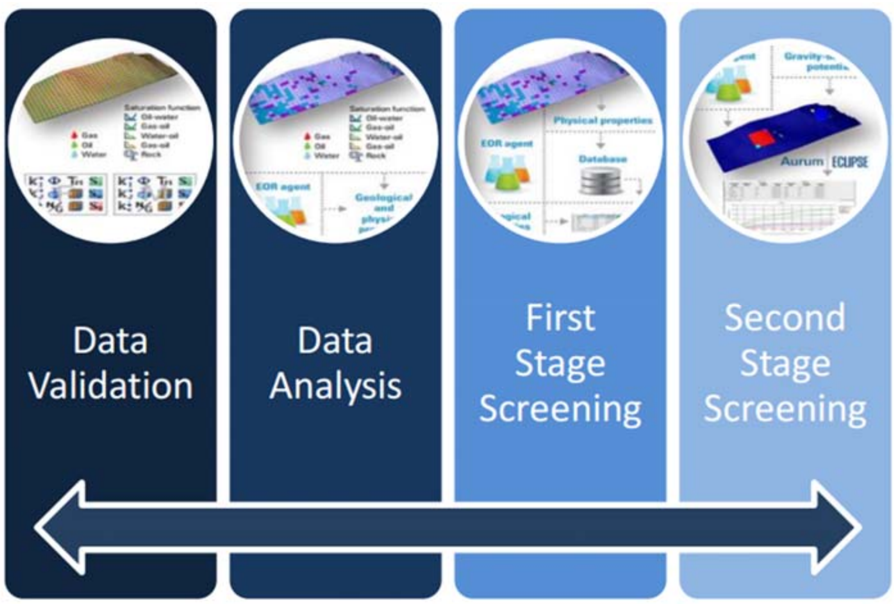
(Moreno, 2014)

Design and implementation steps of an EOR program



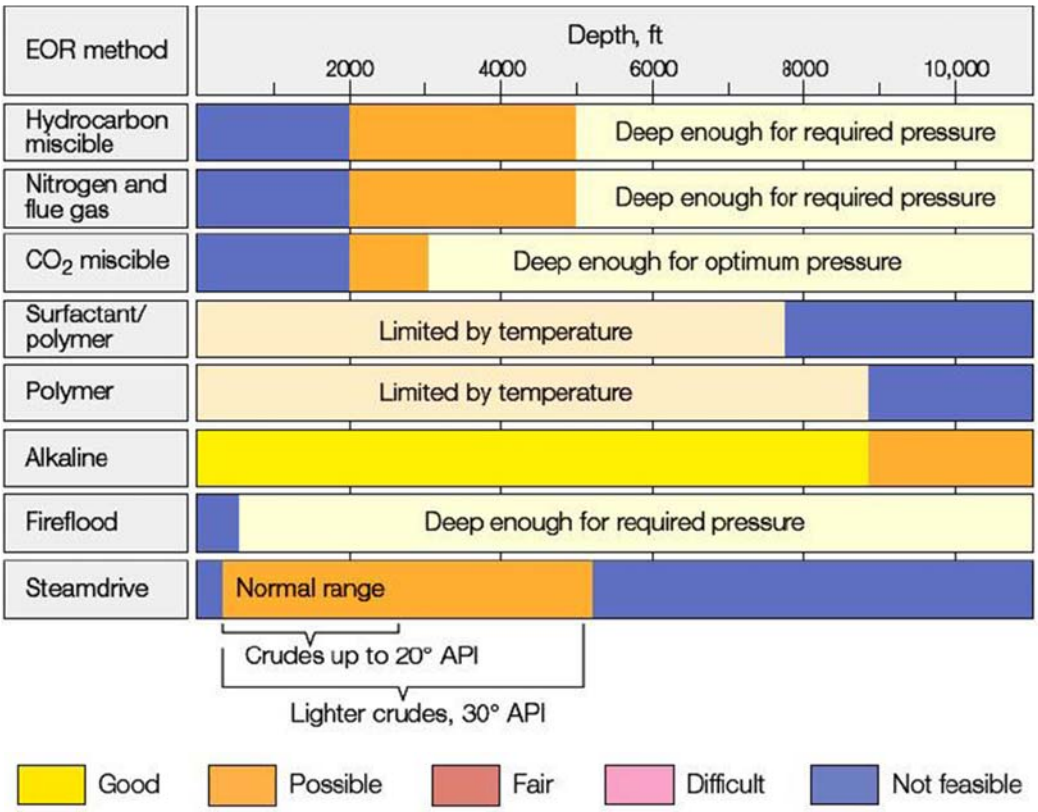
Screening

Overall screening workflow



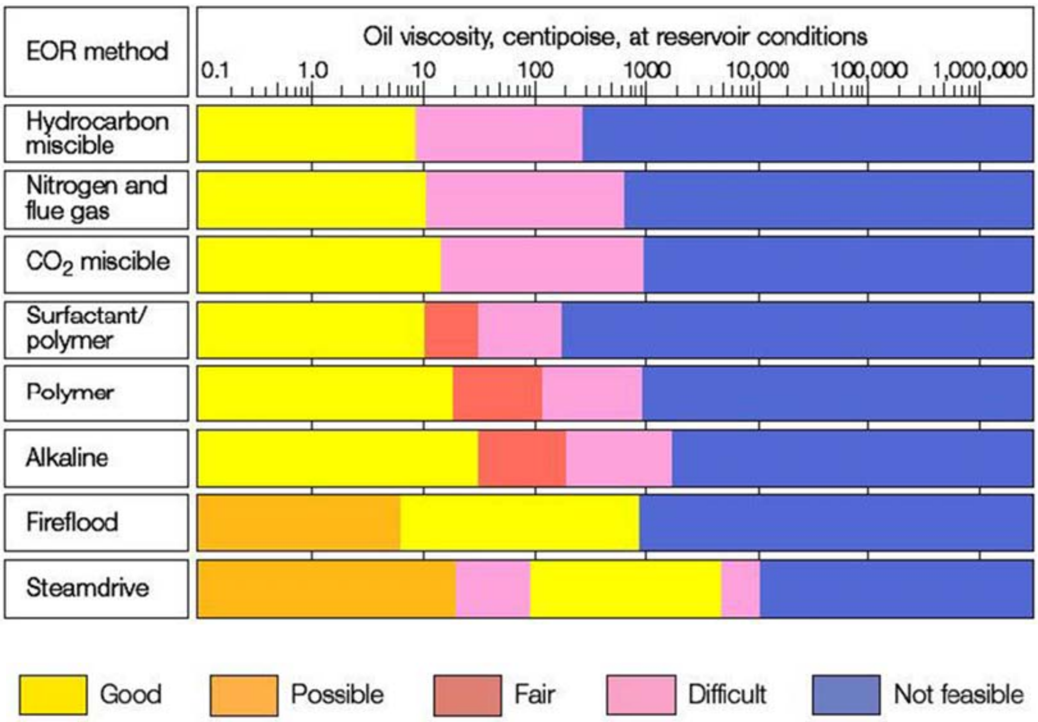
Screening

EOR process screening criteria – depth



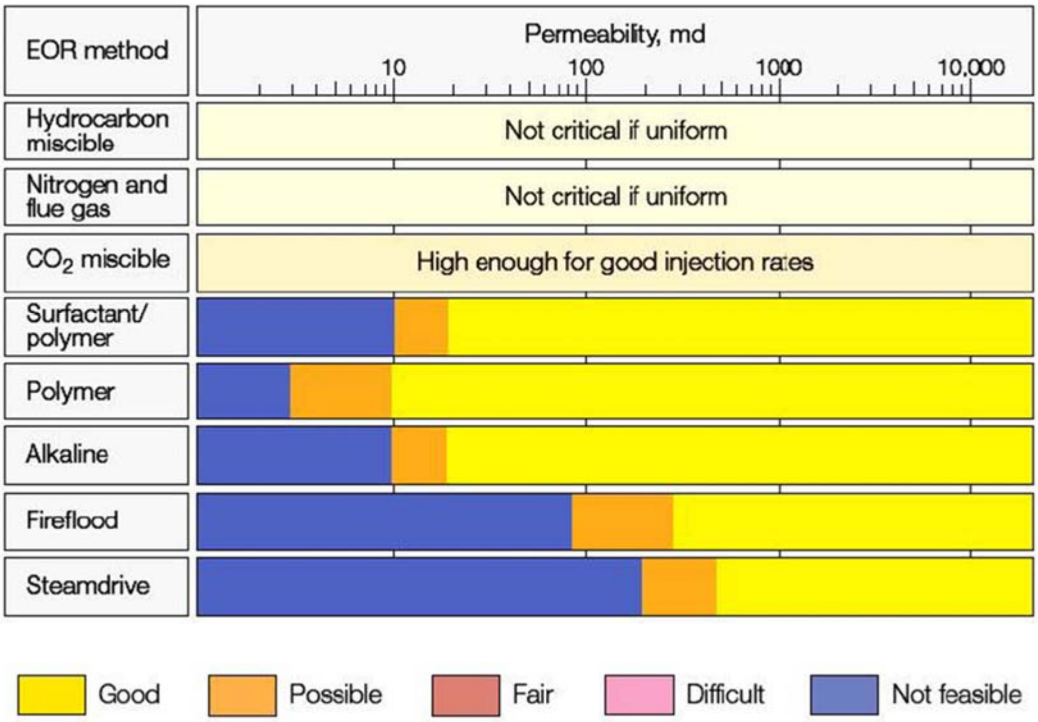
Screening

EOR process screening criteria – viscosity



Screening

EOR process screening criteria – permeability



Laboratory studies

- Based on the results of the preliminary screening study, several laboratory studies should be run to evaluate and assess the performance of the selected EOR method.
- The laboratory studies are undertaken to estimate incremental oil recovery as a function of the injected volume and other process variables.
- The relative permeability and displacement recovery tests on representative cores are conducted under simulated reservoir conditions.
- The physical properties of the system as related to injected agents are also established.
- The expected corrosion and scale problems to the surface piping and equipment should be carefully studied and analyzed.

Simulation study

The reservoir simulation model, capable of mimicking reservoir dynamics as well as the chemical/physical interaction between injection fluid and oil, is a must for planning the full pilot and field project. In this phase, all EOR project design parameters as injectors/producers pattern – type of injection – pilot plant design, etc. are highlighted. At the end of this phase, the production performance for several scenarios will guide to expect and identify the optimal hydrocarbon recovery and the required production facilities such as pipelines, processing units and storage tanks.

Project feasibility

- **Selecting the best and the most feasible EOR technique to improve the recovery is carried out by comparing the net revenue of each proposed scenario.**
- **The net revenue for each proposed scenario depends on**
  1. the production performance and
  2. the economic evaluation.
- **Potential technical risks along with the commercial factors (sources of capital; economic selection criteria; market availability; price of oil; risk tolerance); political factors (economic climatic; issues of safety/security/stability; manpower and technology availability); and government policy (long-term focus; short-term objectives; conservation; posterity concerns; and; employment focus) are also identified and studied.**
- **Then, the necessary recommendations for pilot field application are drawn.**

Field pilot implementation

The EOR technique should be tailored to the reservoir to ensure the efficiency of the selected EOR method in the field. It is specific for a specific reservoir. Field pilot is designed and conducted as a small scale project.

Full field project development and implementation

- **Field wide expansion follows a successful pilot project.**
- **This is the maturity phase of the project. In this phase, the detailed plan to maximize efficient production from the field while optimizing ultimate recovery in a practical timeframe is developed and implemented.**
- **The following design parameters are considered:**
  - Location of the existing facilities
  - Capacity and process description of the existing plant
  - Layout of the area to define the accessibility of the future expansion of the existing facilities
  - Existing pipeline: size, length, maximum and minimum flow rate, battery limits, life time, turn down ratio of the existing pipeline
  - The existing utilities: source of the power generation and the maximum producing power
  - The available capacities of the existing storage tanks

Pilot performance monitoring and detailed simulation studies

The surface and subsurface design parameters, along with the pilot response results are monitored, studied, analyzed and interpreted. The pilot provides much needed information for the final design and provides results that are very useful in fine – tuning of the reservoir simulation model. Then, the technical and commercial evaluation for the full field development plan is carried out. The technical evaluation will consider the following: existing wells location, fluid distribution, chemical requirements, surface facility requirements, preliminary sizing of the required equipment, associated risk, etc.

Key points to keep in mind

Design and implementation steps of an EOR project:

- Data collection, analysis and integration
- Screening
- Laboratory studies
- Simulation runs (segment and full field models)
- Project feasibility
- Field pilot implementation
- Full field project development
- Monitoring the performance of EOR project

6. Case study: Alwyn North – Brent East Panel

Case study outline

- Field development history
- Screening
- Slim tube simulations
- Simulation studies in segment model – Miscible Gas Injection – WAG
- Reservoir monitoring philosophy
- Early field performance of gas injection
- Reservoir management
- Follow up simulation studies
- Conclusions

Field development history

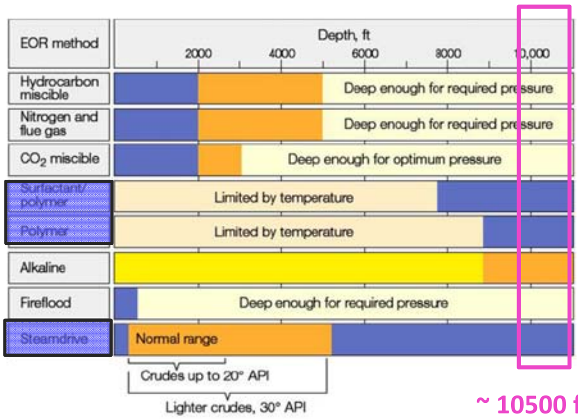
- Discovered 1975. The reservoir is a tilted fault block tilting to the west
- Sequence of sand/silts and shales deposited in deltaic and shoreface environments, ϕ ~ 18% and K = 10 to 800 mD
- Offshore
- First oil: November 1987
- Water injection in early 1988
- MGI was sanctioned in 1997 and first injection was in December 1999. The MGI project was sanctioned including a waterflood phase post MGI and field depressurization, and was evaluated against a continued waterflood scenario

Screening

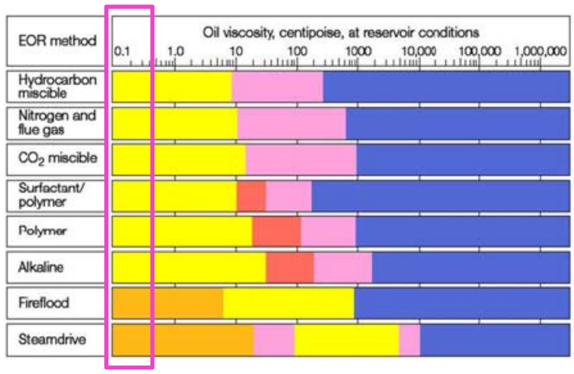
- Reservoir depth ~ ,m TVDSS ~ 10,500 ft TVDSS
- Formations: Tarbert and Ness
  - Upper Tabert: massive sand with good connectivity and permeability
  - Lower Tarbert: poorer quality and more channel like, locally can be good channel sands
  - Ness: channel system with poor vertical connectivity between layers
- Light oil: ~ 39 °API
- Reservoir temperature: 110 °C
- Initial reservoir pressure: 446 bar
- Saturation pressure at 110 °C: 257 bar → undersaturated oil
- PVT properties @ initial reservoir conditions:
  - B_o = 1.64
  - R_s = 196
  - μ = 0.42 cP

Screening

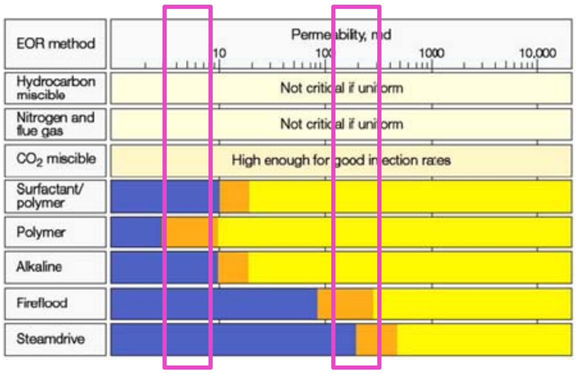
Good | Possible | Fair | Difficult | Not feasible



~ 10500 ft



< 0.42 cP



Ness ~ 10-200 mD
(bad connectivity)

Tarbert ~ 200-500 mD
(homogeneous sands)

Mobility:
$\lambda o = kro/\mu o = 1.9$
$\lambda w = krw/\mu w = 1.1$

Mobility ratio:
$M = \lambda w/ \lambda o = 0.58$

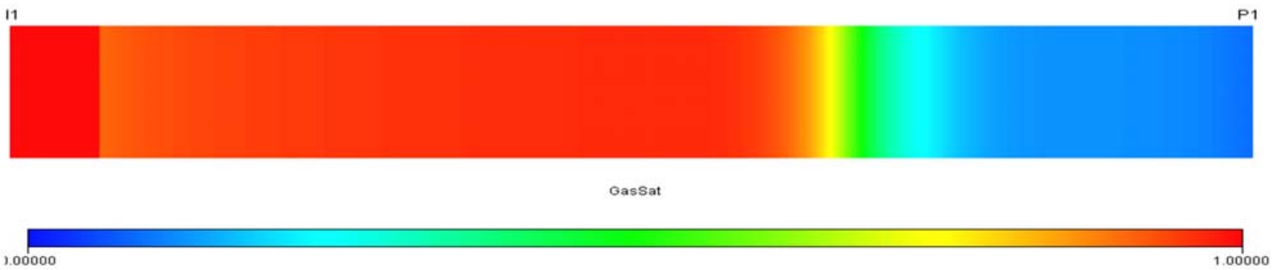
Screening

- Miscible gas injection recommended
- Separator gas and Statfjord gas available

- Studies on MMP

Slim tube simulation

- The purpose of slim tube simulation is to investigate the miscibility pressure (MMP) between the reservoir oil and the injection gases. By knowing the MMP, we can ensure that pressure will be maintained above MMP for gas injection process.
- Slim tube (1D model) used in this case is composed of 500 grid cells with 1m of length in X direction and 10m in Y and Z direction. Injector is located in the first cell (1, 1, 1) and producer is in the last cell (500,1,1).



MMP determination

- EOS was generated using the appropriate laboratory experiments.
- The fluid in place initially is only oil phase, no water present in slim tube.
- MMP between oil-separator gas and oil-lean gas has already determined. The simulation will only investigate MMP of oil-rich gas and oil-CO_2.

Slim tube: model description

- **A very high permeability of the slim tube is used in order to enhance mixing of the gas and the oil and also to reduce the effect of the viscosity gradient.**

Parameter			Comment
Length of Tube	500	m	500 cells of 1 m length each
Porosity	0,3	Fraction	
Pore Volume	15000	RM3	Total Pore volume from .PRT file
Absolute Permeability	50000	mD	
Control Mode	BHP		

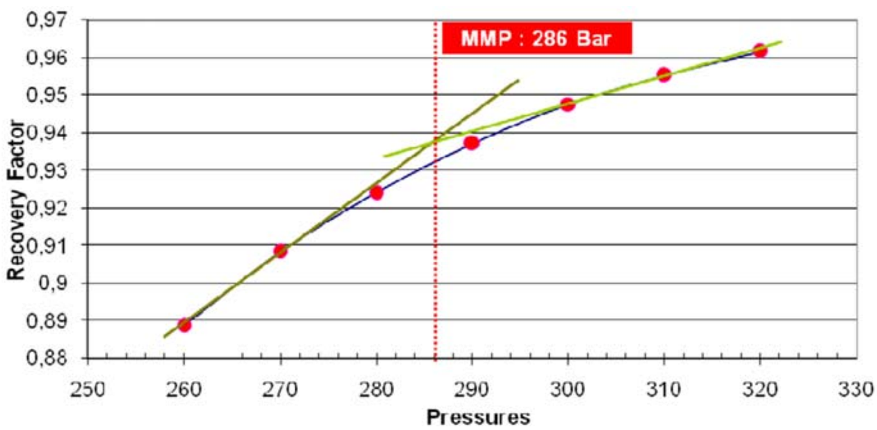
MMP determination

CO2 injection

The simulation of CO_2 injection was ran for different pressures ranging from 260 to 320 bar. The table below shows the oil in place (FOIP), the accumulative production (FOPT) and the recovery factor (RF) as a result of injecting 1.2 pore volume (PV) of CO_2 at pressures indicated

Total Pore Volume	15000	RM3
1,2 PV	18000	RM3
Injection Rate	10	RM3/d
Length of injection	1800	Days

Pressure	FOIP	FOPT	RF
260	8594.55	7638.07	89%
270	8625.32	7834.70	91%
280	8655.27	7998.25	92%
290	8684.43	8138.76	94%
300	8712.85	8256.22	95%
310	8740.56	8349.79	96%
320	8767.61	8431.46	96%

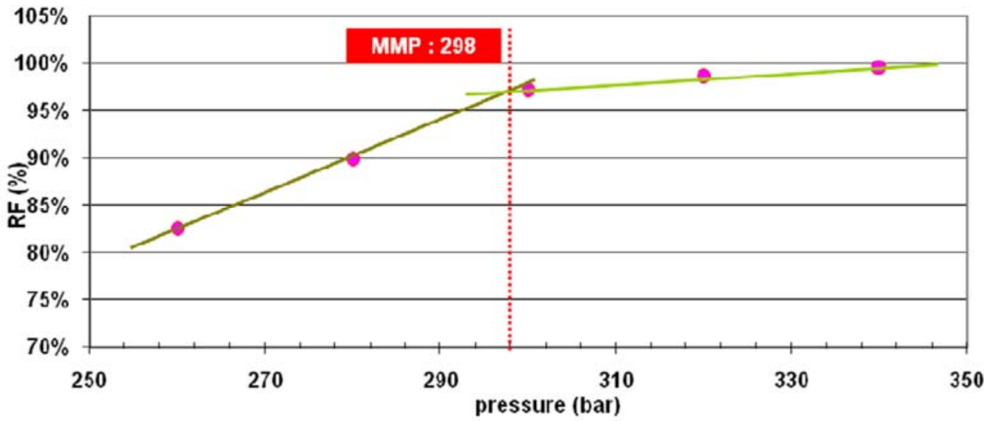


MMP determination

Rich gas injection

The simulation of rich gas injection was ran for different pressures ranging from 260 to 340 bar. The table below shows the initial oil in place (FOIP), the accumulative production (FOPT) and the recovery factor (RF) as a result of injecting 1.2 pore volume (PV) of rich gas at pressures indicated,

Pressure	OOIP	FOPT	RF
260	8594.55	7089.23	82%
280	8655.27	7778.7	90%
300	8712.85	8464.73	97%
320	8767.61	8647.67	99%
340	8819.82	8778.08	100%



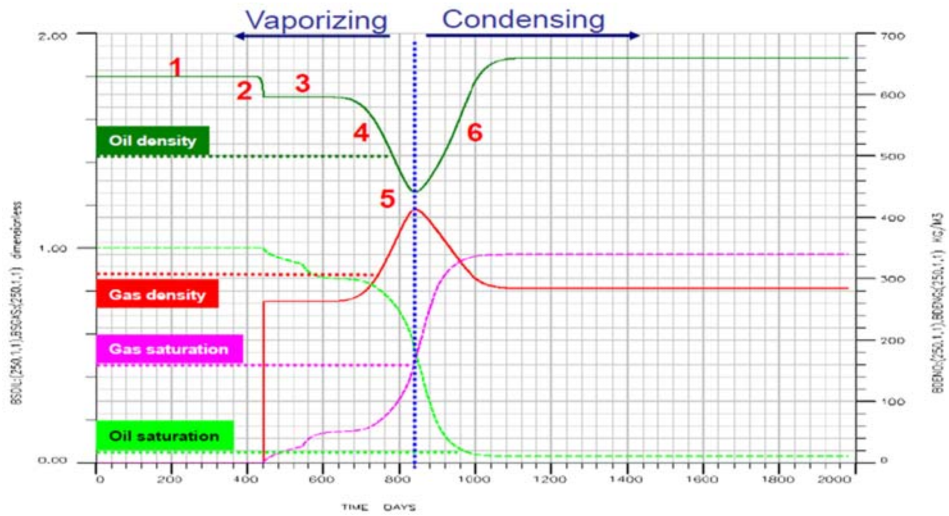
MMP comparison

- CO_2 has the lowest MMP compared to rich and lean gas.
- Separator gas that more or less has the same composition as lean gas has the highest MMP.
- The initial reservoir pressure is 446 bar, which is higher than the MMP of all the gases injected, thus all the gases can be used for miscible injection.
- To inject lean gas and separator gas, higher pressure maintenance in reservoir is required.

Rich gas injection: displacement process

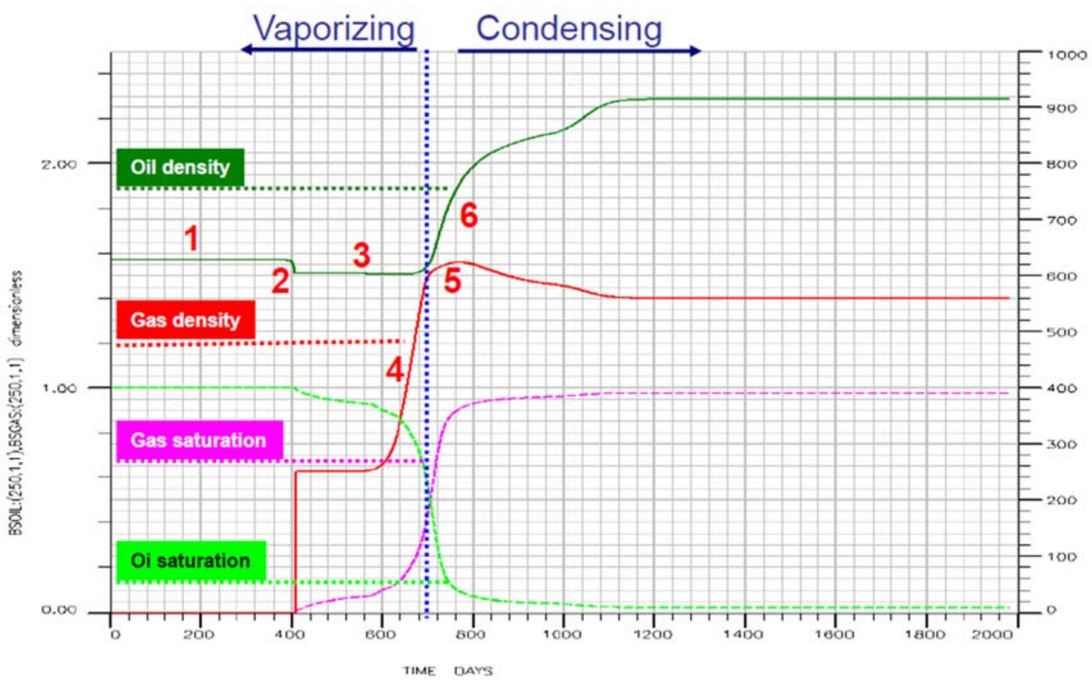
Density and saturation plot of rich gas injection process at 298 bar (MMP) on grid number 250

1. Oil saturation (So) still at its initial because injected gas has not arrived,
2. After the injected gas reach grid 250, gas is dissolved in the oil and it lightens the oil (swelling) hence it reduces oil density, then
3. Gas will act as a free gas,
4. Vaporizing mechanism happens when intermediates of the oil vaporize into the gas thus density-saturation of oil decrease and density-saturation of gas increase,
5. Until it reaches miscibility/near miscibility. In the miscibility region, density difference between oil and gas will be very small and composition of two fluids will be more or less the same.
6. After miscibility occurs, condensing mechanism happens. In this process, intermediate in gas will move into oil because oil density increases and gas density decreases, but gas saturation keeps increasing because more gas injection arrives in the grid 250 and more oil is displaced by gas.



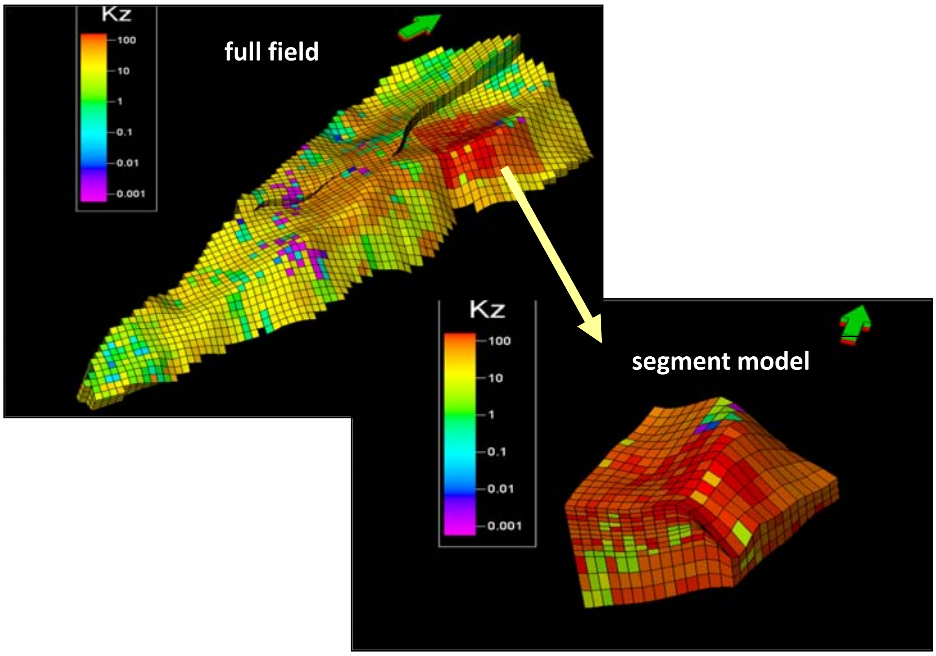
CO_2 injection: displacement process

In the density and saturation plot of CO_2 injection process at 286 bar (MMP) on grid number 250, miscibility on CO_2 occurs earlier compared with rich gas injection. The process (steps 1 to 6) is more or less the same as in rich gas injection.



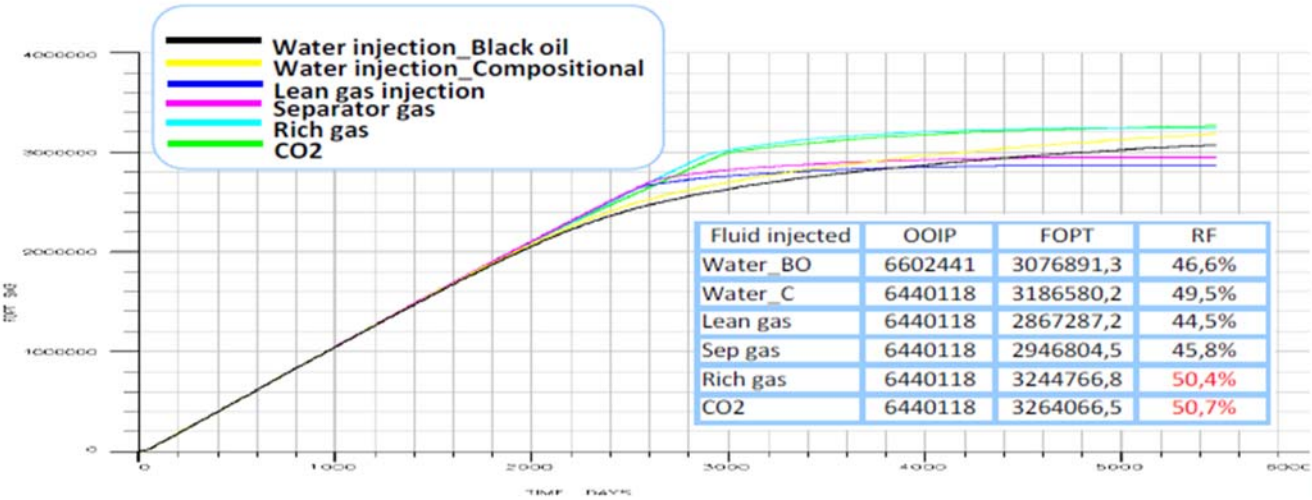
Segment model

The purpose of segmenting a full field model is to evaluate a very sensitive case in a high resolution model. With a segment model, the CPU time can be reduced and a sensitivity study, which requires lots of runs can be made in a high resolution model.



Comparison

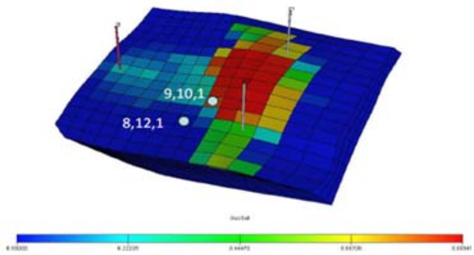
- CO_2 and rich gas injection have a good performance, these two gases have later gas breakthrough.
- The recovery factor (RF) for CO_2 and a rich gas are also higher.
- Lean gas and separator gas act as a immiscible injection, field pressure during gas injection is below their MMP.

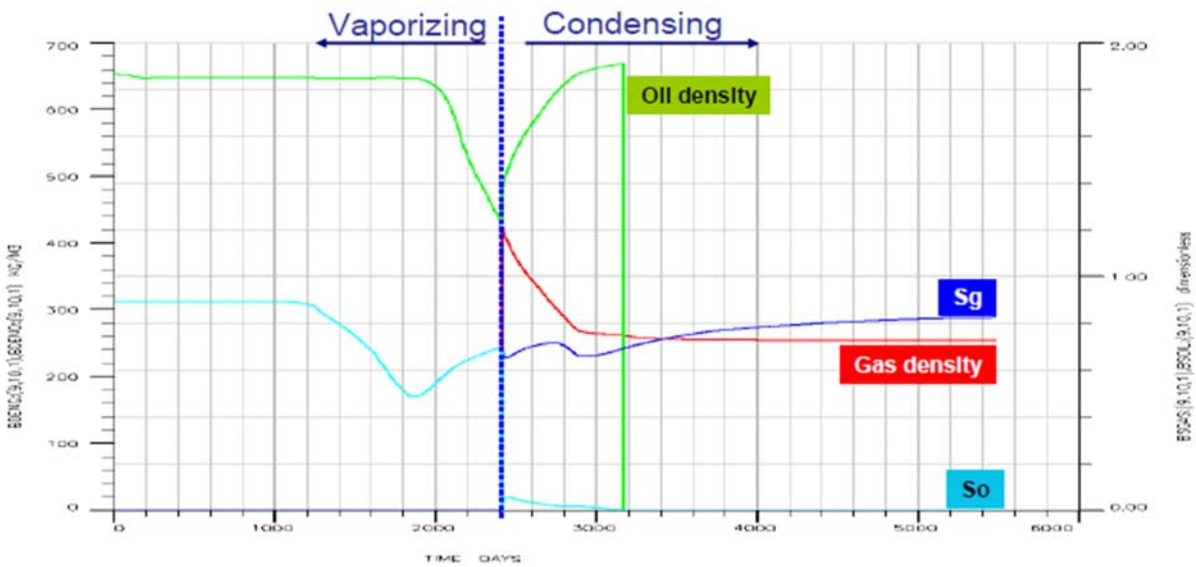


Fluid injected	OOIP	FOPT	RF
Water_BO	6602441	3076891,3	46,6%
Water_C	6440118	3186580,2	49,5%
Lean gas	6440118	2867287,2	44,5%
Sep gas	6440118	2946804,5	45,8%
Rich gas	6440118	3244766,8	50,4%
CO2	6440118	3264066,5	50,7%

Sweep efficiency: rich gas injection

Evidence of miscibility (9,10,1):





Water alternating gas injection

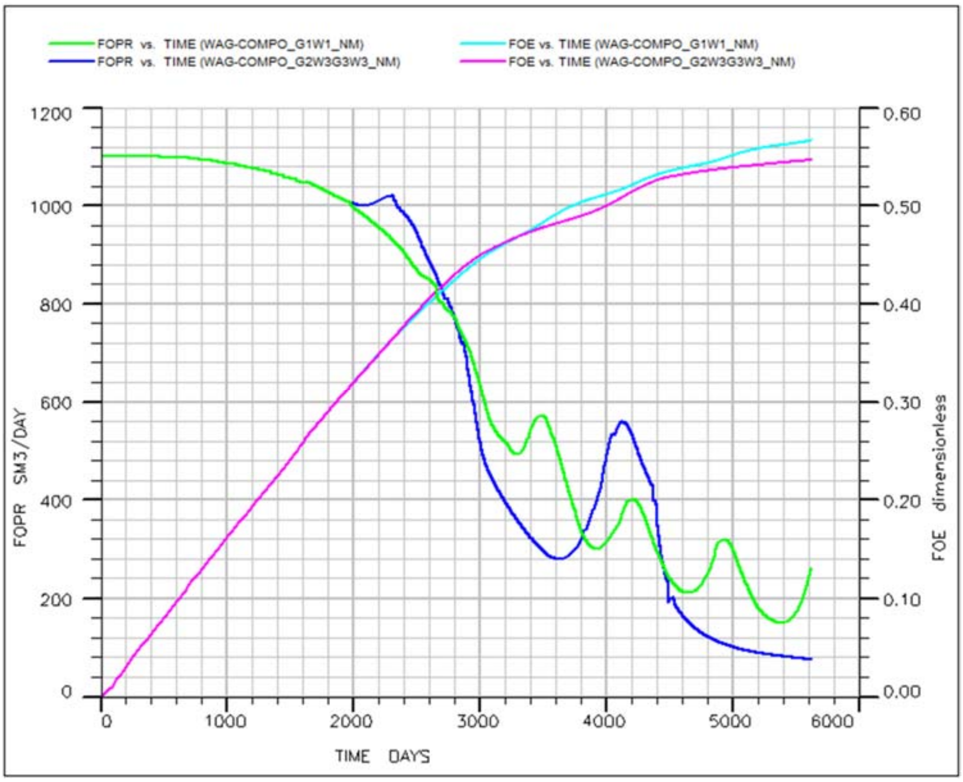
- **The objective is to find an optimized cycle for WAG. As a basis of comparing recoveries we use additional recoveries when WAG is performed (after 4 years of water injection, same start time). In this case the WAG ratio is almost the same (1:1).**

1 1…
GI WI GI WI GI WI …

2 3 3 3
GI WI GI WI …

? ?
GI WI GI WI …

Comparison of the recovery factor



Reservoir monitoring philosophy (1/2)

An intensive reservoir monitoring is carried out to ensure that MMP is maintained and to identify performance changes

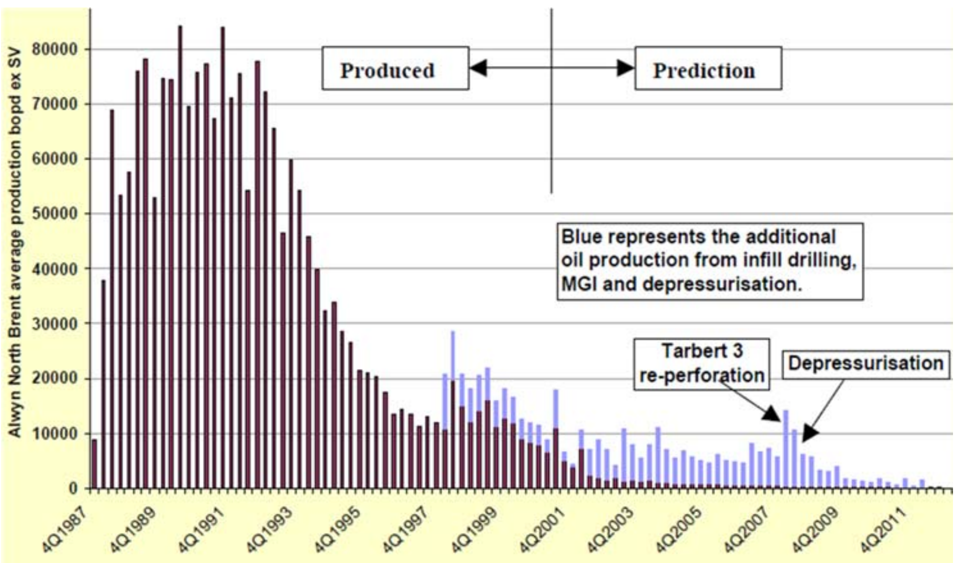
- **Downhole pressure data and surveys: permanent gauges in four key wells. As one well (N10) has been shut for over a year, constant static data have been acquired**
- **Wellhead monitoring: WHFP, WHFT & BSW are daily monitored. WHFP is a key sign of gas breakthrough**
- **Well tests: undertaken on a two-month basis. The trend of oil potential, GOR and WCT evolution are closely monitored.**
- **Flow profiles – PLT data: PLT were run in all the producers before gas injection to provide a baseline and they are run at any change in the behavior of a well (gas breakthrough, thickness of the gas front for sweep efficiency, injectivity indicators, etc…)**

Reservoir monitoring philosophy (2/2)

- **Fluid saturations – RST data: RST were run in 5 producers before gas injection to provide a baseline; the tests indicate the degree of gas banking (no conclusive due to scale and invasion of workover fluids).**
- **Tracers: chemical tracers were injected into each injector at the start of gas injection. Periodic samples have been taken from all the producers for analysis to detect the tracer. These results can be used to help determine the sweep efficiency of the injected gas by means of time of flight versus distance between injector/producers.**
- **Fluid composition: through fluid sampling. Lighter produced fluid has been observed due to the exchange of components between the reservoir oil and the injected gas.**
- **Injectivity tests: injectivity tests were performed soon after the first gas injection and in all the cases injectivity was not a problem.**

Early field performance of gas injection

- **Incremental oil (production and prediction):**



Reservoir management

Good reservoir management is essential to a project of this nature where voidage maintenance is critical. Voidage can be severely compromised if gas cycling occurs on a large scale.

It has been estimated that by mid 2002 around 5 to 9% of the injected gas has been back produced.

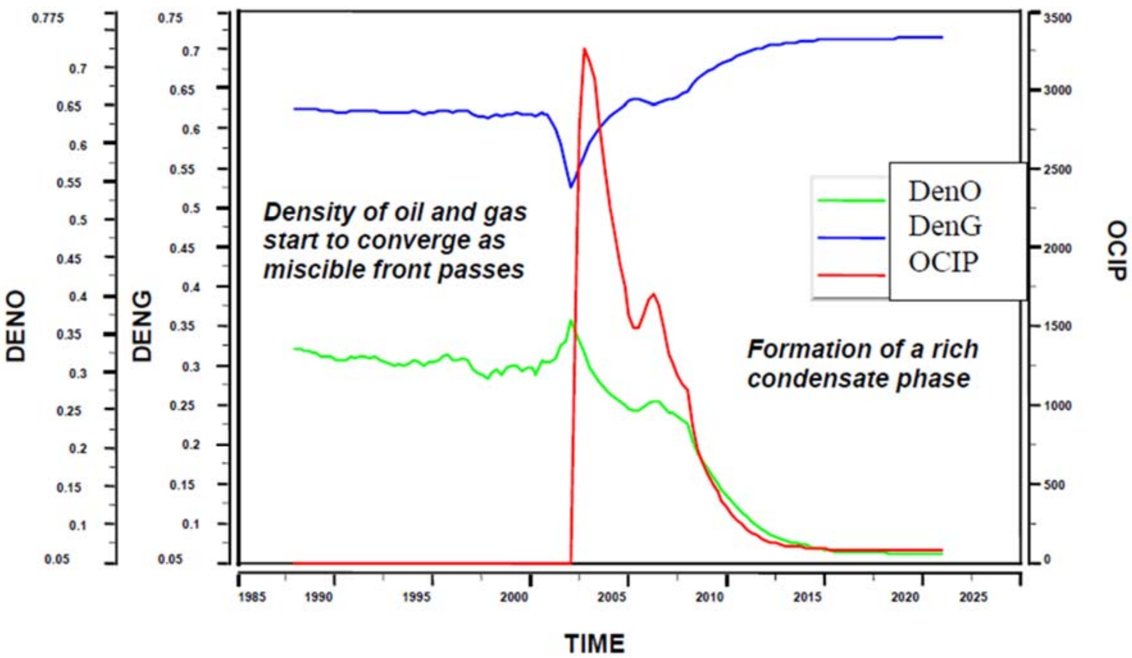
This shows no major problem of gas cycling and indicates that there must be a reasonable sweep efficiency in the reservoir.

Follow up simulation studies

- **Simulation modeling is used for both reservoir management near term and for long term performance predictions.**
- **Using the model as a tool requires the model to be regularly updated.**
- **Detailed simulation studies were carried out:**
  - Zonal gas injection: injecting in the lower zones for a period of time, then switching to the upper zones,
  - Conversion of selected producers to injectors to help with the voidage constraints,
  - Water alternate gas (WAG),
  - Vertical effect of gravity on the macroscopic mechanisms,
  - Lateral effects such as gas conduit in the channel sands.

Follow up simulation studies

- **Evolution of oil and gas density and evolution of rich condensate phase from a selected cell:**



Conclusions

- **Production strategy:**
  - Natural depletion
  - Waterflooding for 12 years in total voidage replacement (1988 – 1999)
  - Miscible gas injection for 5 years – partially in WAG process (1999 – 2005)
  - Blowdown – production with no more pressure maintenance

Comprehensive reservoir simulation studies are key to near term reservoir management as well as long term prediction